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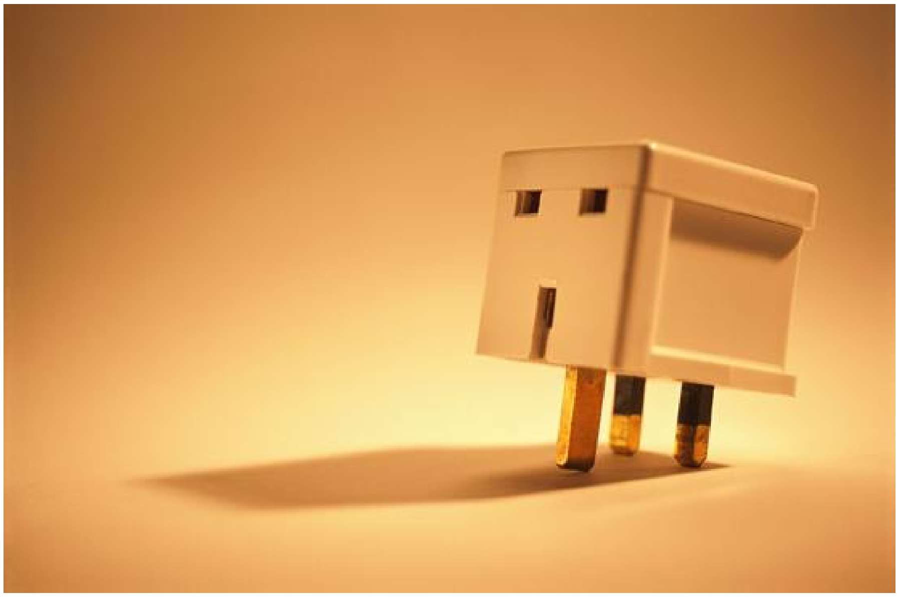
Electric Utilities and Power Primer

Everything You Ever Wanted to Know About Power But Were Afraid to Ask

SUMMARY



KEY POINTS

- This primer is meant to help investors understand the rudiments of electric utilities and power markets. It also covers some of the fundamental drivers of utility stock performance and explains where utility stocks fit in a portfolio.
- We cover both regulated and competitive power markets here. We try to demystify the regulatory process that utilities go through when they apply for a rate case. We also delve into the mechanisms that drive competitive power markets.
- We examine various power generation technologies, as well as the economics behind each major technology and fuel. We provide a brief discussion of carbon pricing and how it might impact the economics of power prices.
- Finally, we have included at the end of this report a number of appendices, including energy measurement, a list of most of the U.S. electric utilities and independent power producers, and information on each state commission. A glossary of common power terms has also been included.

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Electric Utilities' Position in the Market

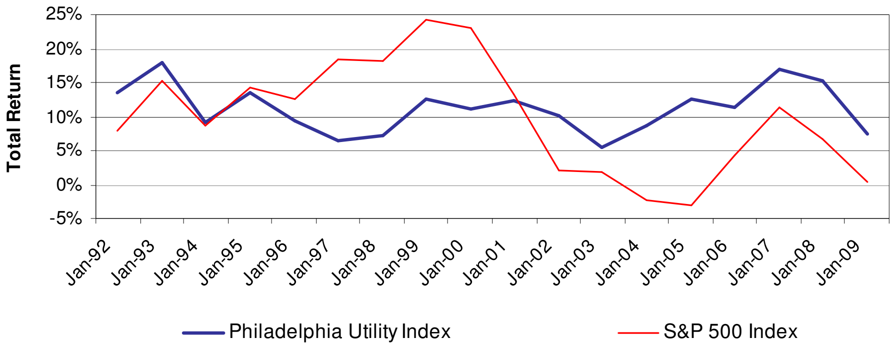
In our travels, we often visit with investors who cover multiple sectors and thus cannot be familiar with all the details of our arcane sector. This primer is designed to give investors a basic understanding of the U.S. electric utility and independent power (IPP) industries, which represent about three quarters of the market capitalization of the U.S. utility industry. The total U.S. utility market capitalization, including electric, natural gas pipeline and distributors, water, and independent power producers, is about $475 billion; we have not included telephone and cable, though these stocks are often found in dedicated utility funds. We have included the independent power producers, as this report covers the mechanism of deregulated power markets. While IPPs share very little of the return characteristics of utilities – they are very sensitive to commodity price movements and do not pay dividends (yet) – they are often included in utility indices.

It is difficult for some investors to justify investing in utilities, for a number of reasons. Not only is the sector viewed as complicated, but it is considered slow relative to the market, over-regulated, and too income-oriented ("might as well invest in bonds"). Furthermore, the utility industry makes up only 3.81% of the S&P 500 (down from 4.1% a few months ago), further deterring investors from the group. It is the eighth smallest of the ten sectors in the S&P 500 (SPX). Even the smallest, telecommunication services, might appear more exciting to investors. On the other hand, 6.6% of the companies in the S&P 500 index are utilities. This is a testament to the fragmented nature of the utility industry. In fact, the largest utility (Exelon at around $30 billion) ranks below the largest company in each sector of the S&P 500 by market capitalization. Among value indices, utilities rank higher: they are the third highest group in the Russell 1000 Value.

We believe that investors would be well served by looking more closely at utilities. Exhibit 1 shows how well a rolling 5-year holding of the Philadelphia Utility index (UTY) would have fared against the SPX since 1992 (with data starting in 1987). As the chart shows, the UTY easily held its own each year except during the tech boom in the late 1990s. The total annualized returns (with dividends reinvested) offered by the utility sector for one year, five years, and ten years outperformed the broad market at -15.3%, +7.4%, and +7.4%, respectively (using a proxy for the Philadelphia Utility index, as the index proper does not factor in dividends) vs. -20%, +0.3%, and -1%.

Utilities are generally expected to pace the overall market in the five years 2008 through 2011, offering about the same total return but with lower risk. Equity strategists as a group expect the S&P 500 to grow earnings per share at a 9.2% rate in the period 2008 through 2011 (assuming it can get out of the 2009 earnings hole, which is down 26% from 2008). The total compounded return of the S&P 500 from 2008 to 2011 would therefore be 11.1% (given its dividend yield of 1.9%). While the consensus earnings per share growth expectation for the defensive electric utilities is about 5.5%, the group's total compounded return would be 11% (5.5% capital gains plus 5.5% dividend yield). The utilities' total return is offered at a lower risk, as the 5-year average beta is currently around 0.6 versus 1 for the S&P 500, according to FactSet.

Exhibit 1: Avg. Rolling 5-Yr. Total Return at 11.2% vs. 9.8% for S&P 500 Since '97



Source: Standard & Poor's; FactSet; Oppenheimer & Co. Inc. estimates

According to our calculations, the total market capitalization of the electric utility and IPP sectors is about $370 billion, with less than 10% coming from the IPPs. This may be a relatively small part of the stock market, but the total enterprise value of these combined sub-sectors is $716 billion, as utilities are heavy users of capital. In fact, the electric utility industry is one of the largest issuers of corporate debt. Capital expenditures amounted to $75 billion in 2008 while revenues totaled $390 billion.

Not all utilities are alike. A key issue to understand about utilities is the evolution of risk within the sector. Whereas twenty years ago the utility sector was a homogeneous group, the group is now divided up, broadly speaking, between regulated and deregulated utilities (including IPPs, which were not even around as a sub-sector twenty years ago). These groups appeal to widely different investment strategies. The notion that investors can pick any utility when they are looking to become more defensive is no longer valid.

In this primer, we focus more on the basic mechanisms that govern how a utility operates than on specific investment themes. The idea of this primer is to give the reader a basic understanding of the primary drivers for the sector, as well as enough background information to follow a utility dialog. Our first section, How to Build a Utility Portfolio, starting on the next page, shows how investors can construct a dedicated utility portfolio. It also outlines the buckets in which we place each utility company, by describing how we sub-divide the sector. The second part of this primer, Operational Chain of Electric Utilities, starting on page 11, covers the nuts and bolts of utility operations. In particular, we explore the various forms of generation. In our third segment, Regulatory Overview, starting on page 32, we introduce investors to the regulatory process, including a typical rate case, and the various players in the regulatory arena. The final section, Deregulation, page 40, opens the way to understanding the deregulated power market, as we introduce investors to the role of marginal cost on a power dispatch curve. At the back of this primer, we have added a number of appendices starting on page 50, as well as a glossary of terms, page 56.

A Note on Method: In most of our broad discussions about utilities, we will refer to the Philadelphia Utility index (UTY) as a proxy for the utility market. The UTY comprises eighteen stocks. The main limitation of the UTY is that it only tracks the price of utility stocks; it does not factor in the dividend. The Utility SPDR (XLU) index provides a better total return analysis given its inclusion of the dividend but it has not been around long enough for most of the trend analysis that we like to conduct. Other indices include Dow Jones Utility (DJU) index, and the various S&P 500 sub-groups: the S&P Electric index, the S&P Natural Gas index, the S&P Multi-Utility index, and the S&P Water index. Some of these indices include non-domestic utilities, thus limiting their usefulness for our purposes.

How to Build a Utility Portfolio

Twenty years ago, electric utilities were a very homogeneous group. The two key differentiation points that investors were concerned about were: 1) What regulatory environment did the utility operate in? and 2) How valuable (if at all) were the non-core investments that the company made to diversify its assets and deploy its positive free cash flow? In those days, many utilities were invested in a number of non-core businesses that ranged from oil and gas exploration and production to airplane leases to low income housing; there were even investments in supermarket chains and banks or savings and loans institutions. Since deregulation was introduced fifteen years ago, utilities have shifted back to their core asset mix: production (in a number of cases unregulated), transmission, and distribution of electricity and, in some instances, natural gas. In this section, we look first at the main sub-group of electric utilities and independent power producers. We then focus on how we would build a genuine utility portfolio that will stay true to the traditional characteristics of utilities.

Four Sub-Groups. We believe that utilities fall into three sub-groups, with the independent power producers forming a fourth sub-group. The three utility sub-sectors are defensive integrated utilities, distribution utilities, and hybrid utilities. The distribution utility group is also a defensive group. Some investors call the hybrid utilities “integrated” but that ignores the fact most regulated utilities own generation, transmission, distribution, and retail operations, making them as integrated as their deregulated cousins. Other terms for the hybrid utilities would be the “deregulated” utilities or even the “generators,” although that would include the IPPs. The term “merchants” typically applies to the IPPs, except for AES Corp.

Defensive. We define the defensive integrated electric utilities as those whose earnings and cash flows are substantially (typically greater than 75%-80%) regulated. These include utilities with regulated generation, electric transmission, electric and natural gas distribution, and regulated electric and natural gas retail operations. Examples are PG&E and Southern. Most of the companies in the electric sector are defensive integrated electric utilities. Regulated utilities typically have relatively predictable earnings and steady cash flows. The prevailing earnings model in this group is driven by regulatory proceedings called rate cases.

Distribution. The second regulated sub-group is the “distribution utilities.” They have been stripped of their generation assets, leaving them with only their transmission and distribution network. They are also known as wires companies or T&D companies. On the gas end, they are called LDCs (local distribution companies); the latter have more in common with an electric wires company, including rate design issues, low trading volumes, and high retail investor ownership, among other elements. Even water utilities could be considered distribution utilities. Consolidated Edison is the largest example of a T&D company. The risk profile of each defensive sub-group is somewhat different, justifying the decision to split the group. Typically, a T&D company will trade at a higher dividend yield and sport a higher dividend payout ratio.

IPPs. At the other end of the risk spectrum are independent power producers like NRG Energy and Calpine. IPPs are typically not regulated at the state level. The main drivers for IPPs are supply and demand pressures, commodity cycles, and the level at which companies hedge their revenue and costs. Earnings and cash flows are quite volatile. The exception is a pure project developer, such as AES. The developer’s business model consists of locking in long-term projects at fixed economics and growing through adding more projects. In some cases, project developers own utility assets. IPPs are not without regulation. Their main form of regulation comes from the Federal Energy Regulatory Commission (FERC), which is in charge of regulating U.S. market power issues. The other important regulatory body would be the Environmental Protection Agency (EPA), although EPA decisions would affect all generation assets, not just unregulated ones.

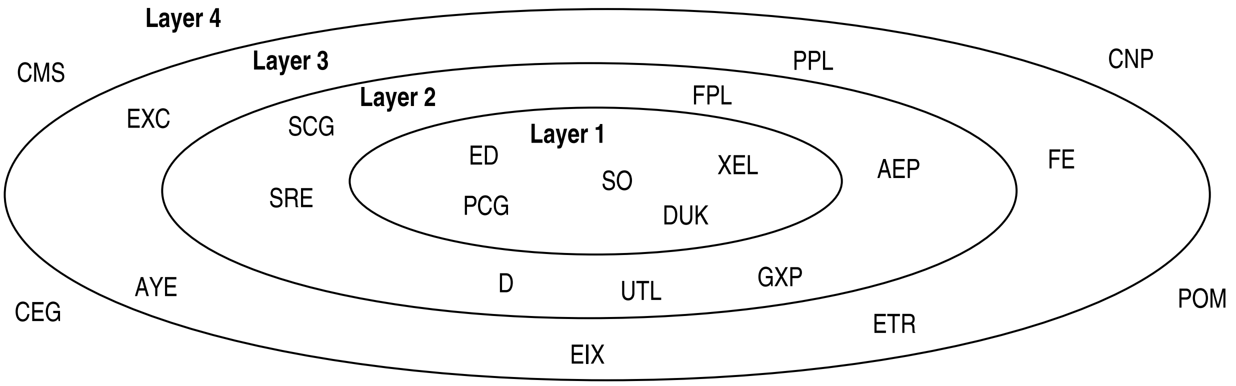
Hybrid. We define the hybrid utilities as companies that have either spun off their legacy regulated generation assets into an unregulated subsidiary or have developed/acquired unregulated generation assets in an unregulated subsidiary. In both cases, the subsidiary is, in essence, an independent power producer, i.e., independent of regulation. Examples are Exelon and FPL Group. We do not limit our hybrid group to utilities that own an IPP. We also include in the hybrid bucket companies that have made sizable investments in or are deriving substantial earnings/cash flows from non-utility assets such interstate pipelines, oil and gas exploration and production, trading, competitive retail, or non-energy related activities. Companies like Dominion or Otter Tail fall into this category. Given the dual nature of hybrid utilities, we analyze their regulated and unregulated assets separately.

Role of Portfolio. With those definitions in mind, we can move to the construction of a utility portfolio. It is important to understand the theoretical role that a utility fund might play in an investor's portfolio contrasted with the reality of how to effectively market a fund. The former would suggest that the fund would be invested to provide a lower risk profile dominated by a sizable income component. The latter dictates that it is sometimes difficult to raise capital with a fund that does not produce relative performance equal or superior to the broader market. This in part explains why a number of utility funds invest in telecommunication stocks even though telecom stocks no longer act like utility stocks.

Style. In theory, a "rational" investor buys utilities to reduce risk (lower beta), to diversify, and to record some current income. The first half of 2008 was a great period to demonstrate the benefit of the lower risk that utilities bring to the table. The flag bearer for defensive utilities, Southern Co., was up 6% in the second half of 2008, when the S&P 500 was down nearly 30%—and these numbers do not even include the two dividend payments that would have boosted Southern's total return to 8.5%. Many retail investors invest in low risk utility stocks whereas institutions are sometimes willing to take on more risk. Smaller utilities tend to have a higher proportion of direct retail ownership, for two reasons. One, the smaller utilities tend to carry a higher dividend, which is more attractive to retail investors. Two, these retail investors often buy the stock of their local utility on principle, whether it is due to familiarity with their utility or to a desire to invest in the community.

Core in Layer 1. Exhibit 2 illustrates our philosophy behind the construction of a model utility portfolio geared toward an investor who is looking for higher income and lower risk. In our view, the core holdings of a utility portfolio are the defensive utilities. In this particular case, for illustration purposes, we have selected Consolidated Edison (ConEd), Duke Energy, PG&E, Southern, and Xcel Energy. These companies are characterized by steady earnings and dividend growth, solid management of utility assets, and, in most cases (ConEd being the exception here), a reasonable regulatory framework.

Exhibit 2: Designing a Model Utility Portfolio



Source: Oppenheimer & Co. Inc. KEY: Layer 1 = Core; Layer 2 = High Income, Less Liquid; Layer 3 = Commodity; Layer 4 = Trading Alpha

Less Liquid in Layer 2. Our second layer in Exhibit 2 is populated with stocks that might offer either a similar high income-low risk profile but are less liquid (e.g., Great Plains, SCANA, or Unitil) or a better earnings profile with a somewhat higher risk profile (FPL Group). Some offer a combination of higher dividend and lower valuation than their peers, such as AEP. We still seek utilities that benefit from either a supportive regulatory framework (Dominion), higher population growth (traditionally Florida utilities would have matched this description), or stocks that represent a key trend in the sector – FPL's wind investment would fit with today's public policy initiatives.

Commodity in Layer 3. Once the first two layers are established, we can let loose and invest in the higher beta names that are dominated by commodity-exposed utilities. We also use the third layer to balance the portfolio back to match some of the weighting of benchmarks against which the fund manager might be judged. Given the sensitivity of commodity prices – in particular natural gas prices – it is important to be cognizant of the stage of the commodity cycle in which we find ourselves. One should note that even though many of the names are commodity driven, we have not listed any of the IPPs in this layer. We also note that when fundamental changes are about to occur, it is prudent to move names to a different layer. For example, if we had a higher conviction that the Senate would pass a cap-and-trade bill that would price carbon, it might prompt us to move Exelon and Entergy from the third layer into the second layer, given their large nuclear exposure. That being said, given their continued exposure to volatile commodity prices, there is little chance that they would make it into the first layer.

Trading for Alpha in Layer 4. The final layer is mostly a trading layer. Again, the tickers listed in Exhibit 2 are illustrative in nature and do not necessarily represent our current trading view. Layer 4 is meant to focus exclusively on alpha creation. As a result, once the alpha movement is realized (whether it is long or short), the fund manager would look to trade out of that position. Each stock that is in layer 4 would have a specific reason for being there, whether we are looking for merger, a dividend cut, a major restructuring, or an estimate cut of over-appreciated earnings relative to consensus. Turnaround stocks would fit nicely in this layer too. The idea is to capture as much alpha as possible. In fact, once the foundation has been established with the core names in layers one and two, the bulk of the work is likely to take place on stocks in layers three and four; being nimble is critical for those layers.

Fundamental Drivers of the Electric Utility Industry

While there are many subtle fundamental drivers for the electric utility and power industry, we believe that generalists should narrow the scope of the analysis. We divide drivers into three categories: drivers for defensive utilities, drivers for utilities with deregulated generation, and general drivers that are applicable to all utilities.

Defensive Utilities

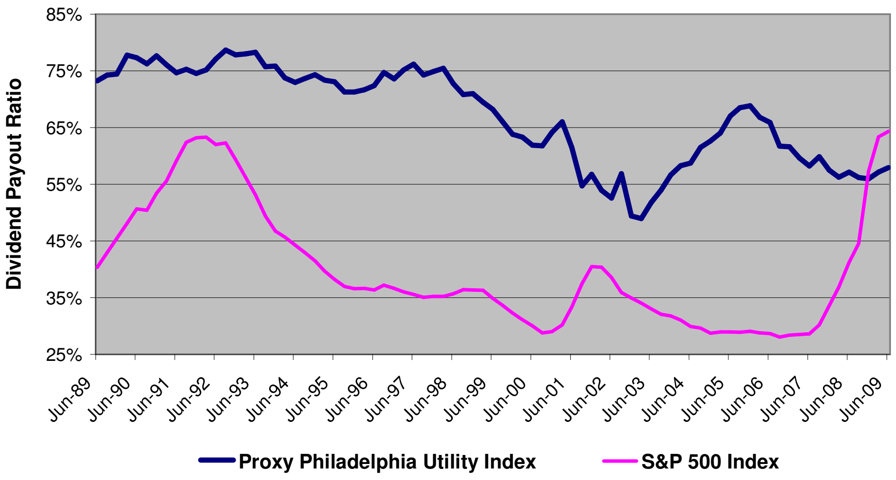
Capital investments. For regulated utilities, capital investments are the most significant driver of growth, as the companies are allowed a return on approved investments. Regulated utilities file with their state commission for approval of the construction project and an appropriate return on the investment. In general, capital investments can be used as a proxy for long-term earnings growth potential. For non-regulated players, the level of capital investments is less important for because the return is not regulated.

State regulatory environment. Electric utilities are governed by many regulatory bodies on the state and federal levels. On the state level, regulators preside over rate cases and decide how and whether utilities recover capital investments. A supportive relationship between the utility and the regulators is likely to lead to a more positive rate case outcome, making it more likely for the utility to recover its investments. Additionally, in a strong relationship the utility may be able to shape regulation and other aspects of the market.

Rate cases. Another significant driver for regulated utilities is the regulatory process, typified by rate cases. These cases establish the potential earnings of a utility in future years, as determined by the commission. Important components of rate decisions are the allowed rate base, return on equity, the equity capitalization structure, and the timing of regulatory relief. In addition, more states are including unique riders that limit regulatory lag. Any change in the components could be a drag or boost on future earnings of the stock. We'll discuss more about rate cases later in this primer.

Dividend policy. Electric utilities stocks are often viewed as "dividend plays," so the company's dividend policy is a fundamental driver for the stock price. Although dividends may change over time, electric utilities tend to maintain a consistent dividend policy, reflecting the visibility of future earnings potential. Exhibit 3 shows how the dividend payout ratio has changed over the years. Note that for the first time in the last twenty years, the market dividend payout ratio in the past year exceeded the utility payout ratio, despite the fact that the S&P dividend yield remained below the average utility yield. It is a testament to the level of earnings deterioration of the broader market.

Exhibit 3: Average Dividend Payout Ratio, 1989-2009

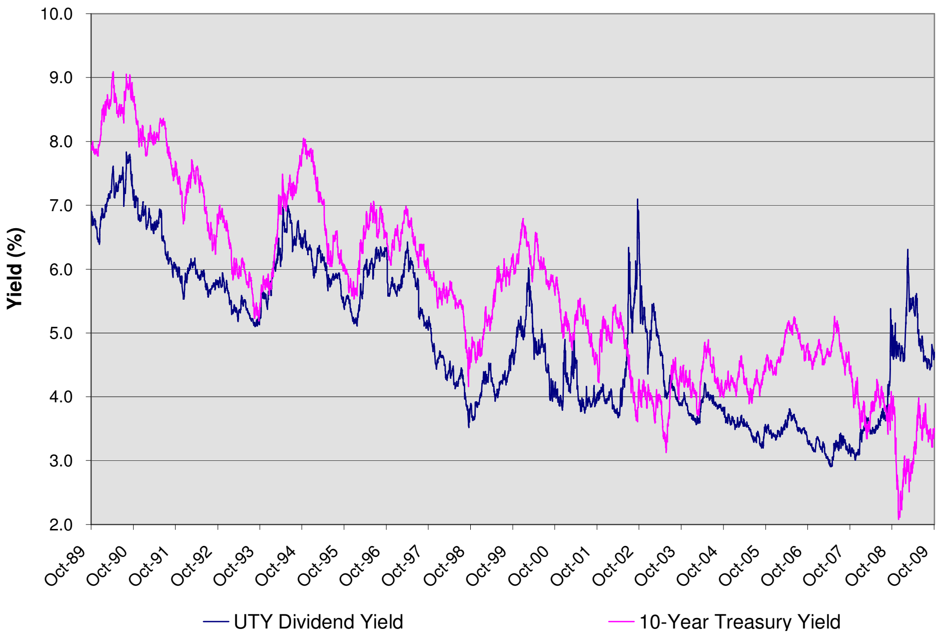


Source: StockVal; Oppenheimer & Co. Inc.

Interest rates. Historically, there has been a strong inverse correlation between the electric utility sector and interest rate movements, making interest rates traditionally the most significant driver of utility investments. Over the last 25 years, the correlation between interest rates and the proxy Philadelphia Utility Index was -0.84 (very tight). The reasons for this high level of correlation are twofold. Firstly, utilities are typically a “dividend play” for investors, given their consistently high dividend payout ratio. In a rising interest rate environment, Treasury bonds become more attractive. As investors shift asset classes from equities to fixed income, utility stocks generally underperform. Secondly, utilities’ balance sheets carry a healthy amount of leverage to finance highly capital-intensive operations. Typically, as interest rates rise, interest expenses creep higher as utilities refinance existing debt or issue new debt to fund capital investments. (Rate cases, however, can allow utilities to reset revenues to cover additional interest costs.)

Recently the correlation has reversed, with a 0.43 correlation over the last five years. In our view, this indicates that stock selectivity remains key, as near-term stock performance choppiness persists. This is particularly evident when examining the 10-year Treasury yield versus a proxy UTY yield (our proxy UTY replicates the UTY, as the index does not include a dividend yield), as shown in Exhibit 4.

Exhibit 4: Proxy UTY Yield Versus 10-Year Treasury: Correlation Turns Negative



Source: FactSet.

Deregulated Utilities

We focus on the following drivers for unregulated generation assets of IPPs and hybrid utilities. A number of these drivers will be covered in more detail in our Deregulation segment.

Commodity prices. Commodity prices are an important driver for utilities that own deregulated generation, as non-regulated generators are allowed to sell the output at market prices and are not required to serve a regulated customer base, also known as native load, at a lower price. In particular the spark spread and dark spread drive changes in margin. The spark spread is the per unit margin for gas plants, which is calculated by subtracting the cost of natural gas from the power price that the operator receives. The dark spread is used for coal fired generation and is the same calculation as the spark spread with the cost of coal replacing the cost of natural gas.

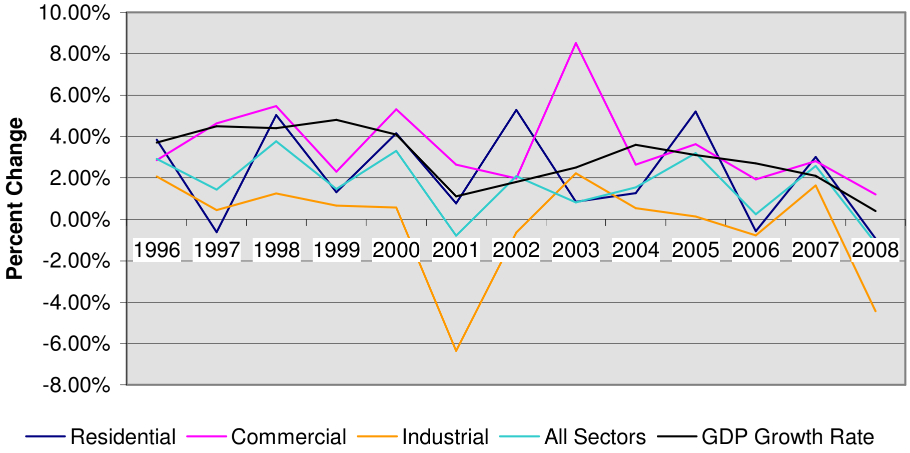
Heat rate. The heat rate is a relationship between the price of natural gas and power, which shows the efficiency of the power market. In addition, the more efficient a power plant is in converting fuel to power, the lower the heat rate of the plant. A high heat rate in the market indicates a "tightening" of the power market because less efficient power plants are being dispatched, which implies increased demand. A higher heat rate should imply higher power prices and thus higher gross margins assuming the gas price remains constant. All else being equal, a rising heat rate is a positive driver for generators.

Reserve margin. A declining reserve margin, which is a measure of excess supply, should benefit existing generation as demand rises faster than supply. In theory, a low reserve margin should imply a higher heat rate and higher power prices and gross margins for generators.

General Drivers

Load growth. Load growth is a significant driver for both regulated and deregulated utilities. A utility's growth is typically driven by load growth in its service territory, whether through regional population growth, increased usage per customer, or customer acquisitions. An increased customer base dilutes fixed costs while improving margins and general profitability. A significant increase in load can also create a need for increased capital investments in new generation and reduce the reserve margin. Load growth that is not adjusted for weather is sales growth. As shown in Exhibit 5, customer sales growth typically mirrors economic growth. In the early 1960s, the demand growth rate for power was about 8%. In today's assumptions, the normal demand growth rate nationwide tends to be about 1.5%-2%, outside of an economic downtown, with the Sunbelt states growing slightly faster.

Exhibit 5: Sales Growth Follows GDP Growth



Source: U.S. Department of Energy, U.S. Bureau of Economic Analysis.

Federal policy. Federal legislators are driving many of the changes in emissions requirements and renewable energy credits that are applicable to all utilities. Federal policy and legislation will dictate future emissions standards for utilities and any necessary reductions in emissions. Renewable tax credits are also available on a national level for wind through 2012, solar through 2016, and for other renewable sources such as hydro, biomass and geothermal.

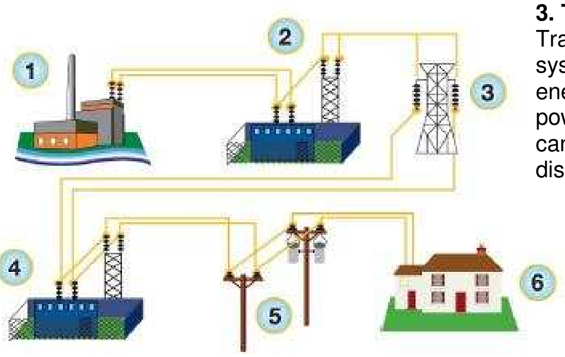
Operational Chain of Electric Utilities

What Does an Electric Utility Own?

The electric utility industry is traditionally divided into three segments: Generation, Transmission, and Distribution. With the deregulation of power markets since the mid-1990s, a fourth segment, Competitive Retail, has emerged. Furthermore, it has become critical to understand the economics of generation plants established by various fuel types and technologies.

Exhibit 6 traces the path of electricity from the power plant to the end-user customer. An integrated regulated utility owns each piece of the chain. In some states, deregulation has separated the generation business and, to a lesser extent, the retail business from the chain. Transmission and distribution (the wires, to which substations belong) have remained regulated, as the advantages of a monopoly structure outweigh any benefit that competition could add.

Exhibit 6: The Electricity System



2. Substation: Voltage is increased to transmit electricity, typically referred to as the “step up.”

1. Generation: Electricity is produced at the power plant.

3. Transmission: Transmission system transports energy to where the power is needed, can be over long distances.

4. Substation: The voltage has to be decreased or “stepped-down” before flowing through the distribution system.

6. Retail: Electricity is distributed to residential, commercial, and industrial customers.

5. Distribution: Power lines owned by local utilities to deliver electricity to customers.

Source: Edison Electric Institute.

GENERATION

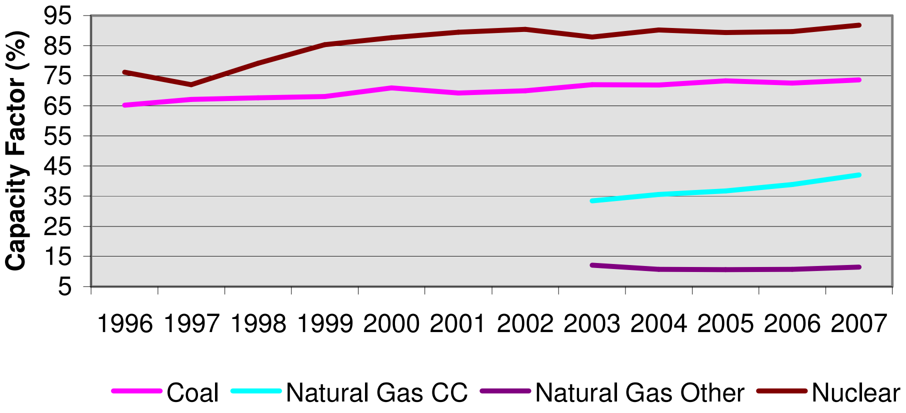
Generation is at the origin of the supply chain. It is also typically the costliest component of power prices, as it commands the most capital spending. In the next few paragraphs, we define a number of terms commonly used in generation analysis. We would refer our readers to the glossary at the back of this report for more terms.

The size or **capacity** of a power plant is expressed in some denomination of watts. There are a thousand watts in a kilowatt (kW), a thousand kW in a megawatt (MW), a thousand MW in a gigawatt (GW), and a thousand GW in a terawatt (TW). Most investors express the capacity of a plant in megawatts, although gigawatts are sometimes used for extremely large projects (giant hydro) and kilowatts are used for very small projects (solar). At the end of 2007, the generation capacity in the United States was about 1,088 GW, according to the Department of Energy (DOE).

However, capacity is not the whole story. We do not consume capacity; we consume **volumes**. Electricity volumes are expressed in capacity per hour, with the two most common being megawatt-hours (MWh) and kilowatt-hours (kWh). As with capacity, gigawatts and terawatts have their equivalent expressed in volume: GWh and TWh. A 60-watt light bulb, commonly found in most U.S. homes, will need 60 watt-hours of electricity to light up a room for one hour. According to the DOE, Americans consumed 4,157 million MWh in 2007.

Once armed with generation and volumes, we can move to the notion of **capacity factor**, which measures how often a power plant runs. Take for example two 500-MW coal plants. While they are identical, Plant A happens to be in Illinois, while Plant B is in Georgia. Plant A has a capacity factor of 40% while Plant B benefits from a capacity factor of 70%. In this example, Plant A will produce 1,752 GWh while Plant B's output will be 3,066 GWh. We obtain these volumes by multiplying the capacity (500 MW) by the number of days in a year (365), the number of hours in a day (24), and the capacity factor (40% or 70%). Of course, we divide the result by 1,000 to reach our volume in GWh. Conversely, for a given capacity and volume, we can determine the capacity factor. Using the DOE 2007 data stated above, the average capacity factor for the United States was 43.6%. Exhibit 7 shows the capacity factor of power plants by fuel type. Natural gas data was not available prior to 2003. Capacity factor should not be confused with availability factor. At 70% capacity factor, Plant B in Georgia is probably enjoying a 90%-plus availability factor. The availability factor excludes days when the plant needs to be out for regular maintenance.

Exhibit 7: Capacity Factor by Fuel Type



Source: U.S. Department of Energy.

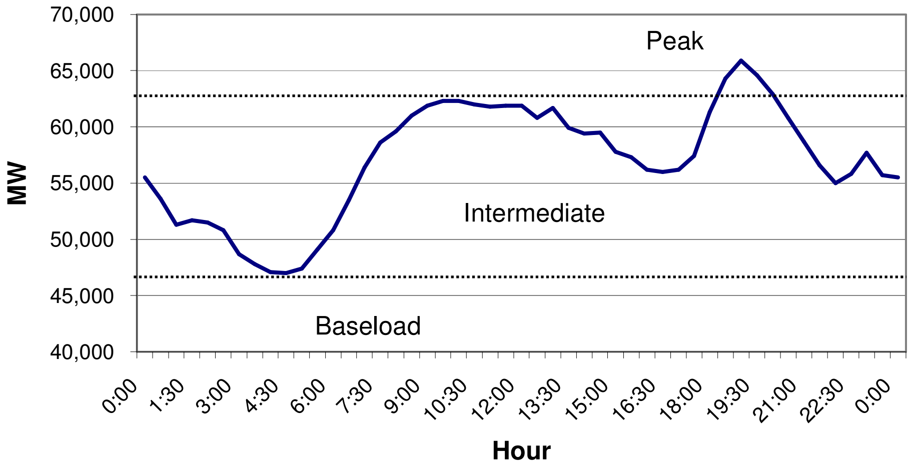
The last two concepts we will introduce are **heat** rate and **spark spread**. The heat rate of a power plant is also known as the efficiency ratio. It is the amount of British thermal units (Btu)—a measure of energy—it takes to produce one kWh. A 7,000 heat rate plant is more efficient than a 12,000 heat rate plant, as it only takes 7,000 Btu to produce one kWh for the first plant, whereas it takes 12,000 Btu for the second plant to produce the same kWh.

The spark spread is essentially the gross margin of a plant. Let's assume that the marginal price of power in the Texas market is $50 per MWh. A 7,000 heat rate natural gas plant producing power at $35 per MWh will book a $15 per MWh spark spread. We will have more on this topic later in this primer (see page 43).

Daily Power Cycle

Demand for power falls in three categories. Exhibit 8 shows a typical October day in France. As shown, 4 am seems to be low point in power usage. Residential customers are sleeping although some of their appliances like refrigerators are still running. Factories are also consuming electricity. In this example, we designate the capacity in use below the line at 46,500 MW as baseload power. Power that is used on a permanent basis—baseload—is constantly running throughout the day. As we hit 5 or 6 am, people wake up and get ready to go to work. The public transportation runs more (electric) trains to accommodate the movement of rush hour. By noon, the power activity surpasses 60 GW, before hitting a lull until rush hour picks up again. Most of the variability during the day is intermediate load. Finally, the Frenchmen get home and cook (using electric stoves) while watching television, causing an abrupt surge in electricity demand. This leads to a peak in demand by 8 pm.

Exhibit 8: Daily Demand Creates Power Cycles



Source: EDF Group, Oppenheimer & Co. Inc.

Baseload demand. This kind of demand is the bottom rung of the supply/demand electric dispatch curve, as it embodies the "base" or threshold level of consumer demand. Baseload generation typically represents about 60% of a utility's total generating volume capabilities. In the United States, coal and nuclear-fired capacity are the primary fuel sources for baseload generation because of their low variable costs and the static nature of the demand. The higher fixed costs can also be easily spread out given the predictable demand profile.

Intermediate load. Power plants that serve the intermediate load (also known as mid-merit) are load following plants: output is adjusted during the day in line with demand. As the load increases, the most efficient plants are brought online first. The intermediate load typically accounts for 30% of generation volume. One type of plant that is used for intermediate load demand is combined cycle gas turbines—although when natural gas prices are low enough, they can act as baseload plants. Intermediate load plants typically feature moderate fixed and variable costs and some operational flexibility.

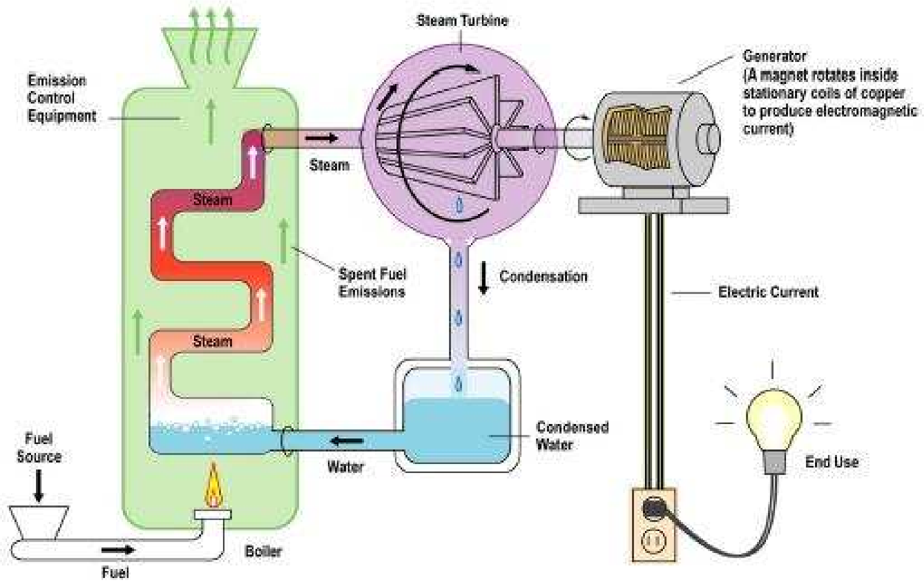
Peak demand. As indicated by the name, this kind of demand rests at the top of the demand spectrum and represents about 10% of all generation volume. Demand at this level is reached occasionally during a “peak” in customer usage. Extreme demands on the system, such as extreme temperatures, could cause generators to dispatch peak as a last resort. Unexpected demand can also prompt peak to be dispatched even if some intermediate plants are available, as speed to market becomes critical. Internal combustion and simple cycle gas turbine (SCGT) plants are often used to meet this level of demand because their low fixed costs and short lead times to come online allow for maximum operational flexibility. However, peakers generally suffer from high variable cost (fuel) and lack of durability.

Generation Technology

There are various types of electric generation technologies. These include steam turbines (which uses mostly nuclear, coal, and natural gas), simple cycle gas turbines (SCGT), combined cycle gas turbines (CCGT), cogeneration, hydroelectric, wind and solar. All but the most specialized technologies, such as fuel cells or solar photovoltaic technology, ultimately use a generator to create, or “generate,” electricity.

Steam generation. In steam generation, a specific fuel type is burned in order to generate heat to create steam. The heat is applied to a water boiler that turns water into steam. As the steam rises and leaves the system, it passes through a steam turbine. While moving across the sloped blades of the turbine, the steam turns the blades by applying rotation force. The rotation force is then transferred to the generator as magnets rotate within the center. Outside the magnets are coils of wire and as the magnets rotate the direction of the magnetic current inside the coil changes. The change in magnetic current causes a change in magnetic flux, which results in a decline in voltage and triggers the creation of electricity. Fuels used for steam turbines include nuclear, coal, oil, natural gas, geothermal (steam generated from the earth), and waste. Nuclear fission is just another way to create heat. Exhibit 9 depicts the steam generation process.

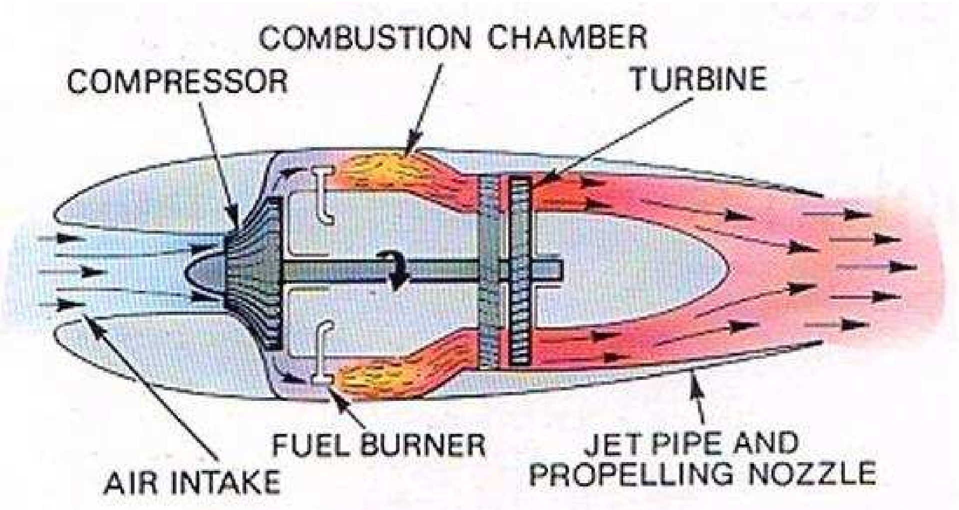
Exhibit 9: Electric Steam Generation



Source: Edison Electric Institute.

Simple cycle gas turbine or combustion turbine (SCGT). SCGT and CCGT use a fuel source, typically natural gas, to turn the turbine to create electricity. When the injected fuel with injected air in high pressure burns, it creates force. This force will rotate the generator. There is no need to heat up water to reach a critical level of steam before the turbine can rotate. As a result, one advantage of this technology is the shorter time it takes to ramp up to full production. Also, the construction cost is lower and the cycle is shorter than other technologies. This characteristic makes SCGTs particularly well suited for peaking needs.

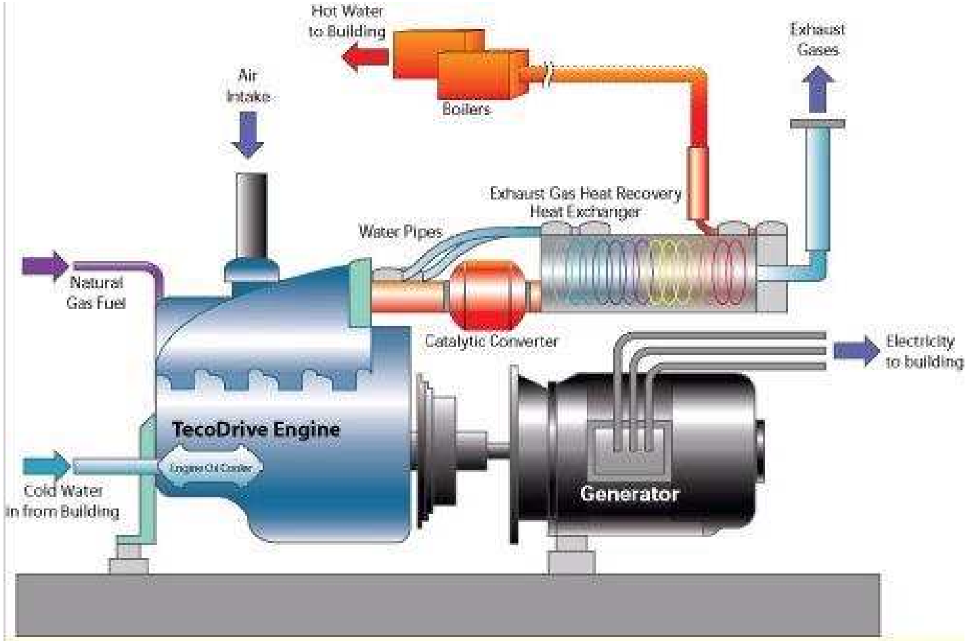
Exhibit 10: Simple Cycle Gas Turbine is like a Giant Jet Engine



Source: www.aerospaceweb.org.

Cogeneration. This technology allows the steam force from a SCGT to be utilized in more than one way or to create both steam and heat. When steam is created by boiling water with a fuel source, not all the steam is used to power the turbine. Instead, some of the steam is piped to a facility for use as steam heat. This is another case of cogeneration: the force created from the injected air and ignited fuel rotates the turbine. During this stage, a heat by-product is released. The heat is then redirected to the heat exchanger, where cool water is moved through the exchanger. The transfer of heat from the gas to the water leaves cold gas to be emitted, as shown in Exhibit 11. Oftentimes, cogeneration facilities will pipe steam to nearby factories to be used for processing.

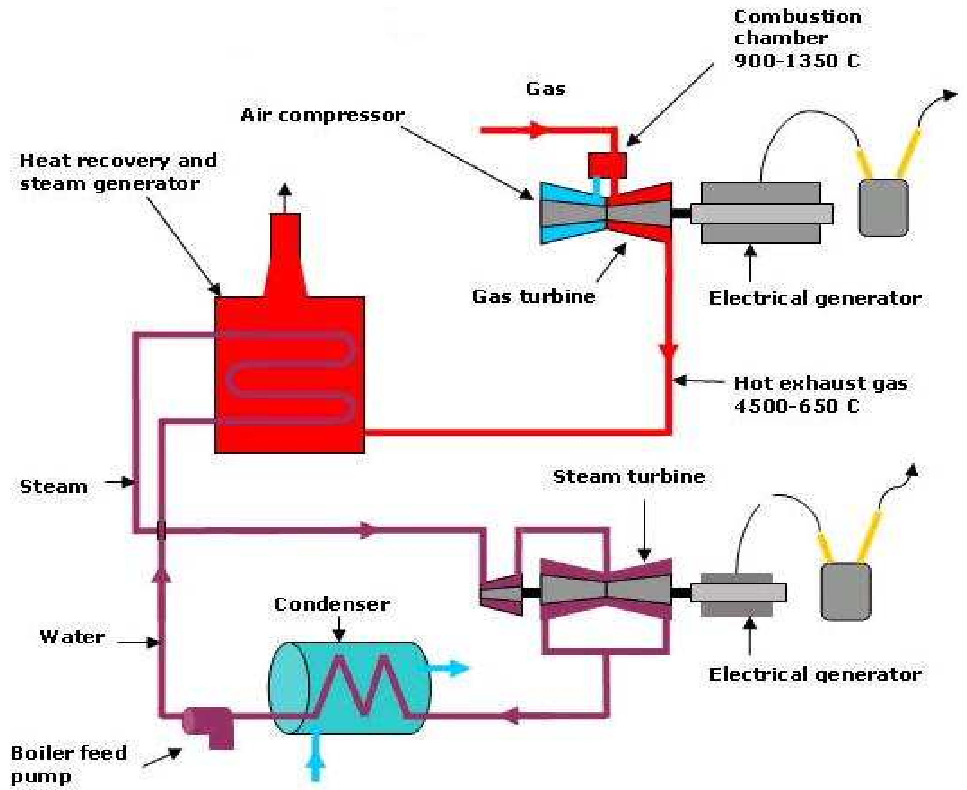
Exhibit 11: Cogeneration



Source: U.S. Environmental Protection Agency.

Combined cycle gas turbine (CCGT). CCGT technology combines the SCGT and cogeneration. Instead of using the heat exhaust for an industrial process, the heat is applied to a boiler, from which steam is generated and flows to a second turbine to rotate a second generator, as shown in Exhibit 12. Thus, with one fuel, an operator can turn two turbines (or more, in some cases). This technology increases efficiency and lowers the heat rate.

Exhibit 12: Combined Cycle Generation Turbine (CCGT)

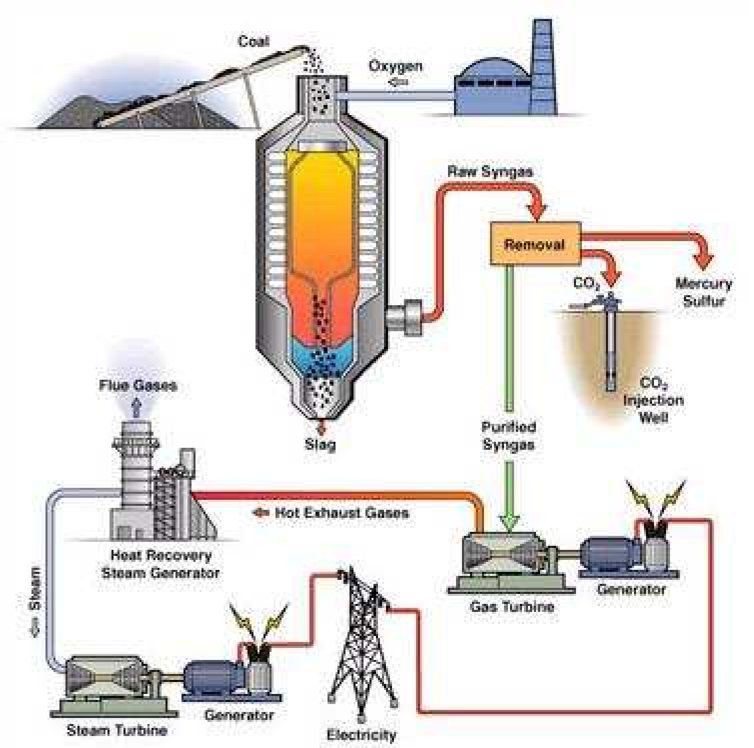


Source: climateandfuel.com.

Integrated gasification combined cycle (IGCC). IGCC combines coal gasification and combined cycle technologies. First, the powder form of coal, or another fuel source, is combusted with oxygen and steam in a gasifier to produce a mixture commonly known as "syngas," which is a combination of carbon monoxide, carbon dioxide, and hydrogen. The mixture is "cleaned" as sulfur compounds and mercury are removed. After purified syngas is produced, it is used as a fuel source in combined cycle gas turbines to create electricity. Typically, an IGCC plant will have gas turbines, a heat recovery steam generator (HRSG), and a steam turbine.

There are several advantages of the IGCC technology. It is viewed as a cleaner option for power generation as the coal gasification process removes some sources of pollution, such as sulfur and mercury, prior to syngas being combusted. It is also viewed as an alternative to the installation of emission control mechanisms on traditional coal-fired plants. IGCC technology is considered to be more efficient in lowering emissions of NO_x, SO_2, mercury, and, to a lesser extent, CO_2. Another advantage of IGCC technology is a greater flexibility in which fuels can be used. In particular, IGCC technology allows the usage of coal with higher sulfur content. However, the construction and installation costs of IGCC technology remain steeper than other options.

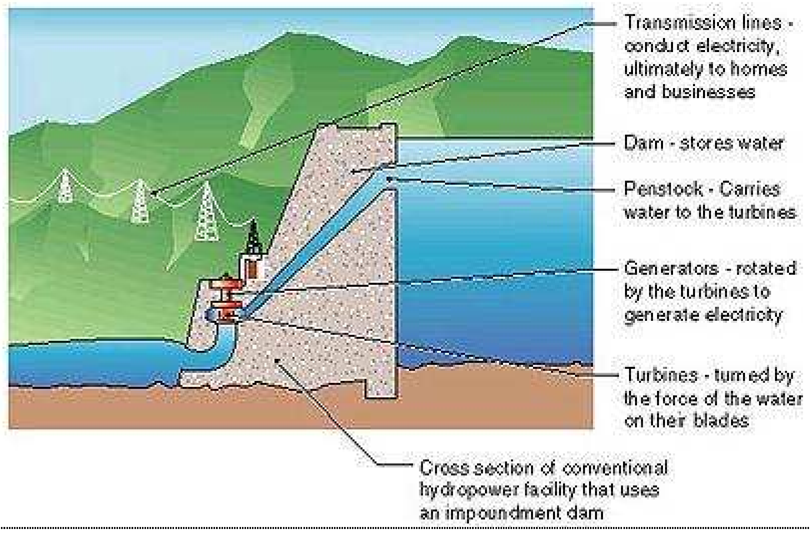
Exhibit 13: Integrated Gasification Combined Cycle (IGCC)



Source: Natural Resources Defense Council.

Hydroelectric power generation. Hydropower uses water and gravity to rotate a turbine. Water is usually collected at an elevated height. As needed, a dam will release water to flow downstream. The kinetic energy of the falling water hits turbine blades. As the water flows across, it causes a rotation that generates electricity. Hydroelectric generation provides the only method to effectively store electricity, if operating a pump storage hydro plant. With pumped storage, operators are able to run the hydro power generation plant during the peak hours when power prices are higher and pump the water back up to higher elevation during the off-peak hours when power prices are lower.

Exhibit 14: Hydroelectric Generation


Transmission lines - conduct electricity, ultimately to homes and businesses

Dam - stores water

Penstock - Carries water to the turbines

Generators - rotated by the turbines to generate electricity

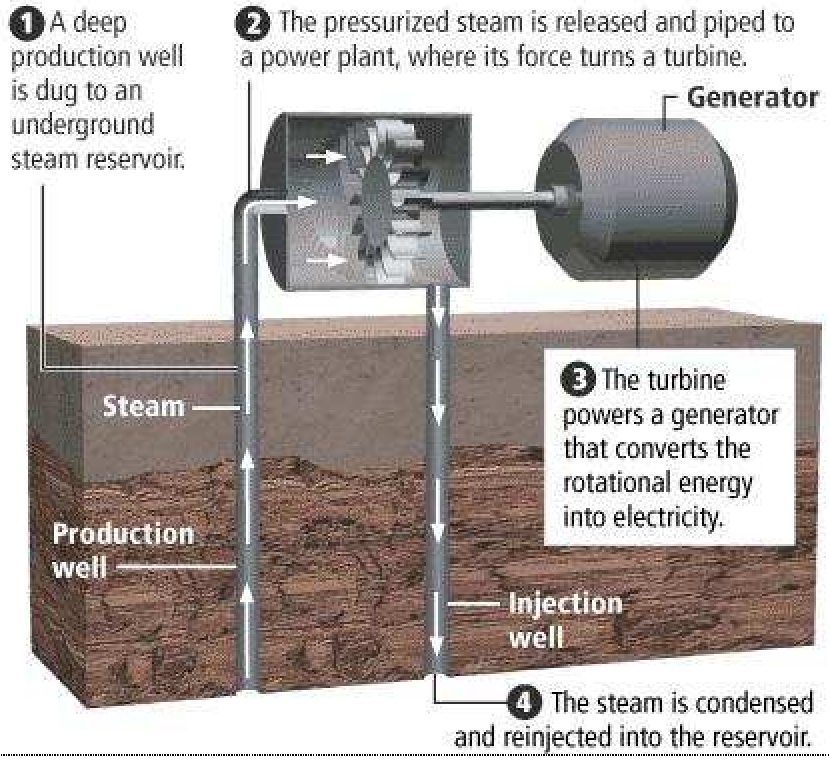
Turbines - turned by the force of the water on their blades

Cross section of conventional hydropower facility that uses an impoundment dam

Source: U.S. Department of Energy.

Geothermal power. Geothermal energy is a clean, renewable resource that uses heat stored in the earth to generate electricity by bringing the steam or hot water to the surface through wells, as shown in Exhibit 15. The force of the steam turns a turbine which then powers a generator to convert rotational energy into electricity. There are three types of geothermal power plants: direct steam, flash, and binary. Dry steam plants use geothermal steam directly to turn turbines. Flash steam plants pull deep, high-pressure hot water into lower-pressure tanks and use the resulting flashed steam to drive turbines. Binary-cycle plants pass moderately hot geothermal water by a secondary fluid with a much lower boiling point than water. This causes the secondary fluid to flash to vapor, which then drives the turbines. The type of plant built depends on the type and temperature of the geothermal resource at the site. Geothermal energy has high fixed costs and low variable costs with an average capacity factor around 95%. However, in the U.S., most geothermal reservoirs are located in the western states of Alaska, and Hawaii.

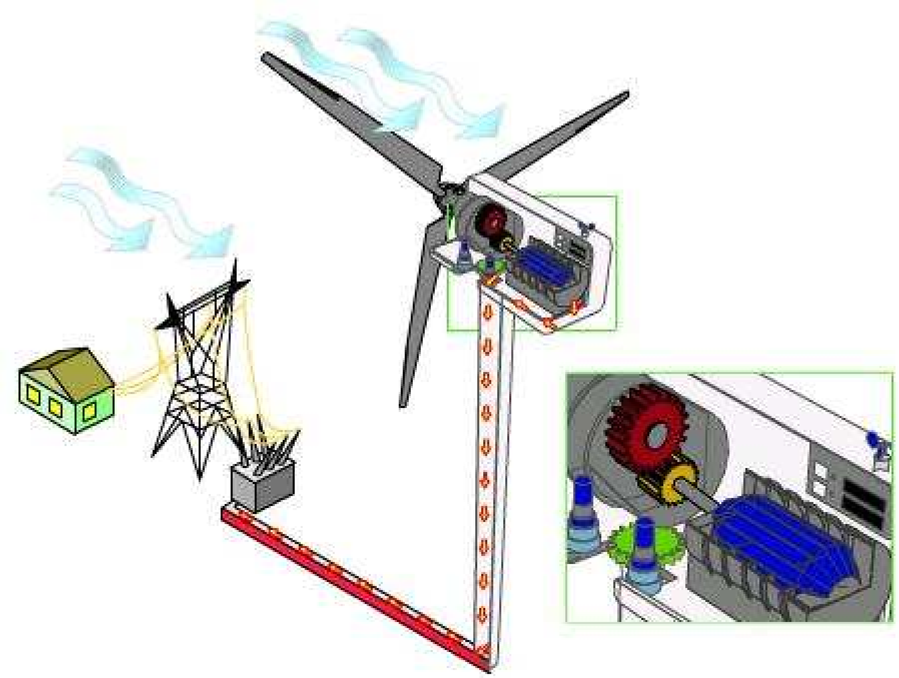
Exhibit 15: Geothermal Energy


① A deep production well is dug to an underground steam reservoir.
② The pressurized steam is released and piped to a power plant, where its force turns a turbine.
Generator
③ The turbine powers a generator that converts the rotational energy into electricity.
Steam
Production well
Injection well
④ The steam is condensed and reinjected into the reservoir.

Source: U.S. Department of Energy.

Wind power. Wind is a clean and renewable form of energy. The kinetic energy in the wind turns the blades of a wind turbine, which spin a shaft, which connects to a generator and makes electricity (see Exhibit 16). Wind energy is one of the lower priced renewable energy technologies, but is not always cost competitive with fossil-fueled generators. The initial cost of a wind farm is high, though variable costs are very low. The major challenges to using wind as an energy source are low capacity factors and high transmission costs, as the wind resource is intermittent and the strongest wind resources are in remote locations far from cities and transmission lines. In addition, wind energy cannot be stored effectively.

Exhibit 16: Wind Turbine

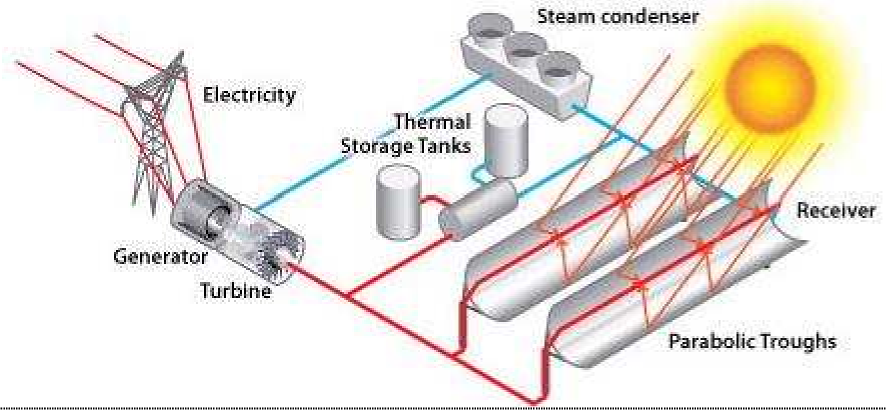


Source: U.S. Department of Energy.

Thermal solar (concentrated solar power). Solar thermal technologies use mirrors to reflect and concentrate solar radiation onto receivers which heat a working fluid. This thermal energy can then be used to produce electricity via a steam turbine or heat engine driving a generator. Concentrated solar power systems are classified into three main technologies: linear concentrator systems, dish/engine systems, and power tower systems. The major difference is the manner in which the mirrors are arranged, as shown in Exhibits 17-20.

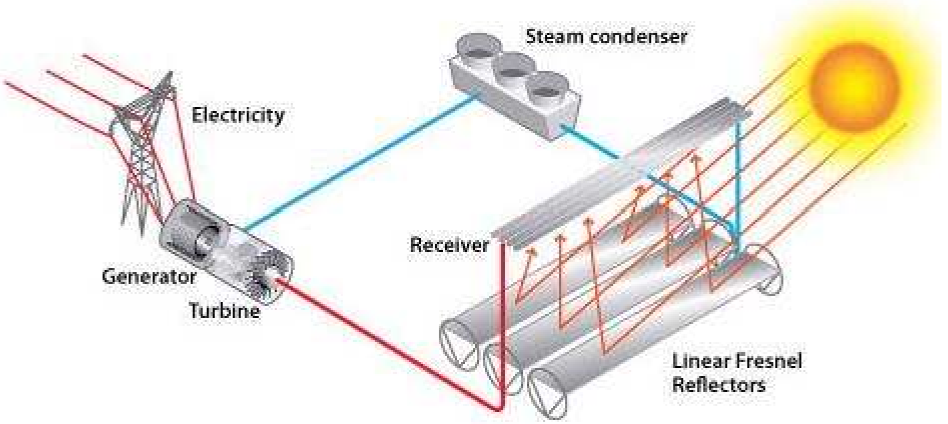
Linear collectors capture the sun's energy with large mirrors that reflect and focus the sunlight onto a linear receiver tube. The receiver contains a fluid that is heated by the sunlight and then used to create superheated steam that spins a turbine that drives a generator to produce electricity. Linear concentrator systems include parabolic trough systems and linear Fresnel reflector systems. Parabolic trough systems are the predominant solar power system currently used in the United States. Trough designs can incorporate thermal storage where a storage system is heated during the day and can be used in the evening to generate additional steam to produce electricity.

Exhibit 17: Parabolic Trough System



Source: U.S. Department of Energy.

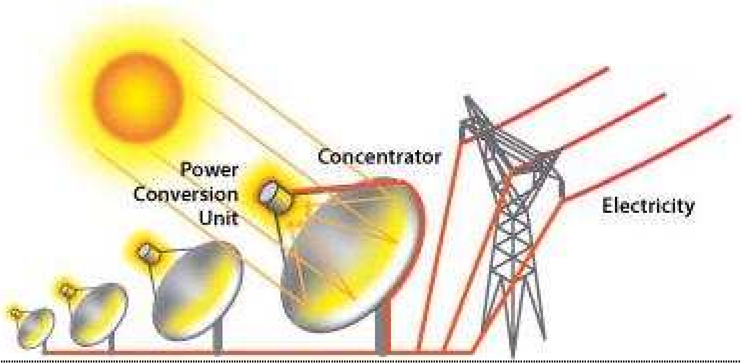
Exhibit 18: Linear Fresnel Reflector System



Source: U.S. Department of Energy.

Dish/engine systems produce relatively small amounts of electricity compared to the other thermal solar technologies. A parabolic dish of mirrors directs and concentrates sunlight onto a central engine that produces electricity.

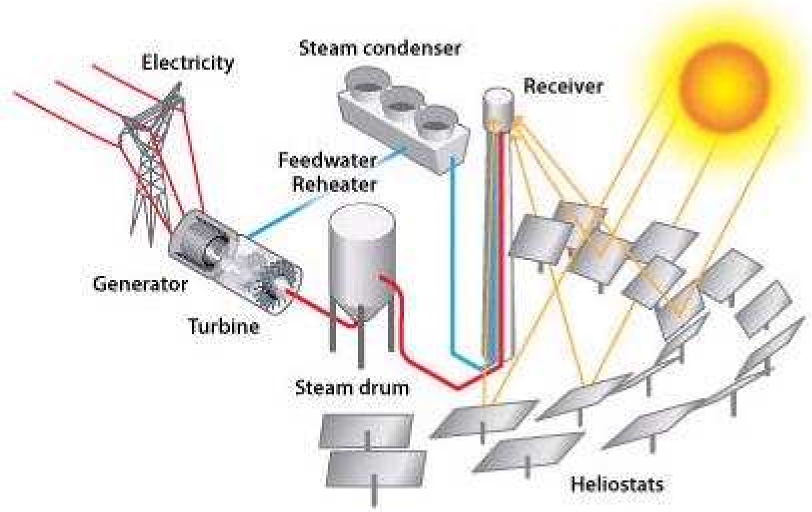
Exhibit 19: Dish/Engine Systems



Source: U.S. Department of Energy.

Power towers use many large flat sun-tracking mirrors (heliostats) to focus sunlight onto a receiver at the top of a tower. A heat-transfer fluid heated in the receiver is used to generate steam which pushes a turbine to power a generator. Power towers offer higher solar-to-energy conversion efficiency rates.

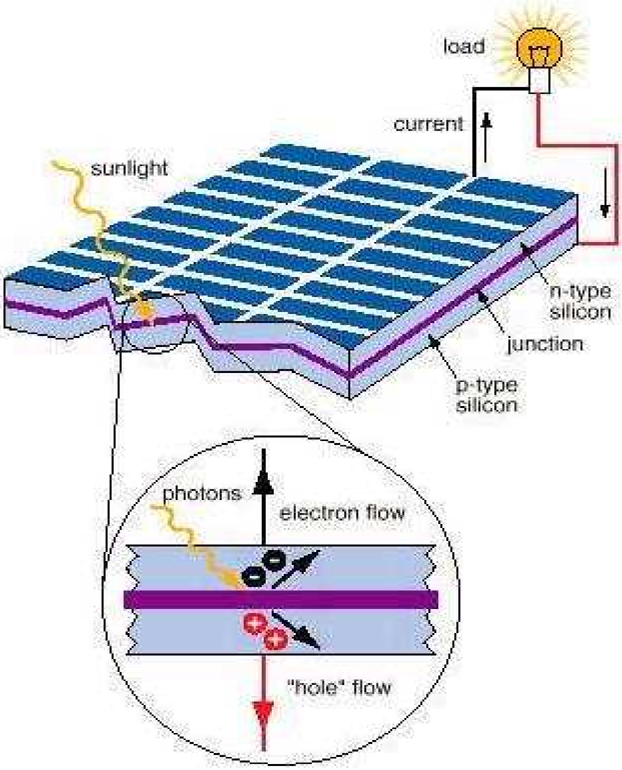
Exhibit 20: Power Tower



Source: U.S. Department of Energy.

Photovoltaic solar. Photovoltaic cells (solar cells) convert sunlight directly into electricity. As shown in Exhibit 21 on the next page, photovoltaic cell consists of two thin sheets of a semiconductor, usually silicon. One sheet will be positively charged and one negatively charged, establishing an electric field between the two sheets. As sunlight hits the silicon, some photons from the sunlight are absorbed. The energy of the photons is transferred to the semiconductor, knocking loose free electrons, and electricity is produced. If a conductive pathway is introduced close to the electric field, a current will flow through the conductor pathway to be distributed externally. With solar cells, a generator is not needed to produce electricity. Photovoltaic cells are still very expensive and are not yet economical in locations with a low solar resource. In the United States, the strongest solar resource is in the Southwest.

Exhibit 21: Photovoltaic Solar Panel

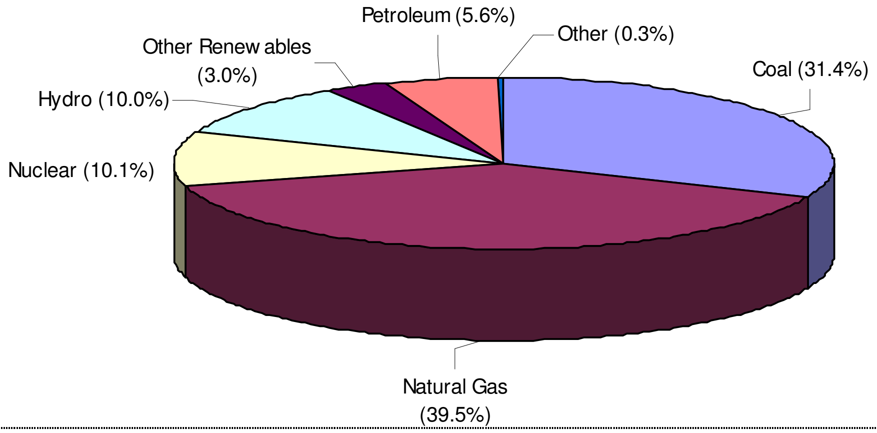


Source: Research Institute for Sustainable Energy.

Selection of Fuel: Primary Driver of Cost

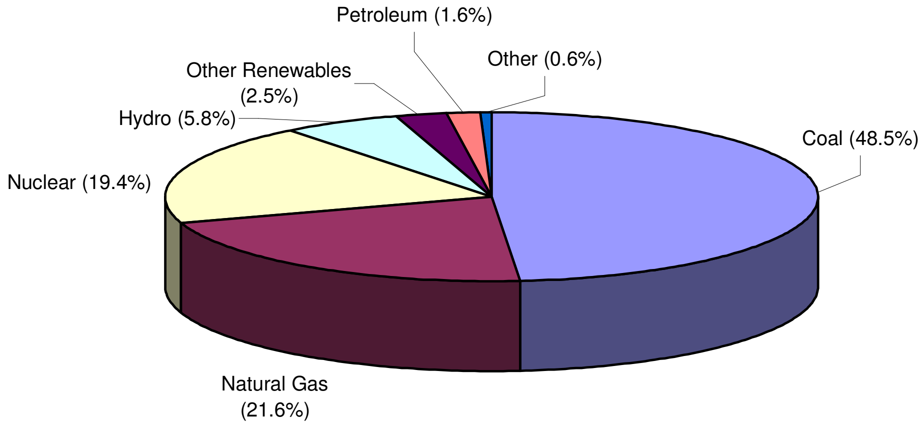
Fuel costs are a primary factor in determining the associated marginal and variable costs of running a plant, i.e., the economic advantages of the power plant. Fuel costs determine whether a power plant will be dispatched to serve a competitive market. Thus, the lower the fuel costs, the higher the economic advantages the power plant has over other competing power plants. Exhibits 22 and 23 show the percentage of available capacity by various fuels used and the amount of electricity generated by each fuel type.

Exhibit 22: Generation Capacity by Fuel Type, 2007



Source: U.S. Department of Energy.

Exhibit 23: Generation Output by Fuel Source, 2007



Source: U.S. Department of Energy.

Coal: Almost half of the U.S. electricity is produced by using coal as the primary fuel source given its large domestic supply and low variable cost. Although the installed capacity of natural gas fired generation is greater, coal plants typically run more often than natural gas plants due to coal's low variable cost. However, coal-fired plants have many drawbacks. Coal plants are costly ($2,200-$4,000/kW) and have long build cycles and high pollutant emission rates. There are varying types of coal – Appalachian (Northern, Central), Interior and Western (Power River Basin) – each with different applications, economics, and qualities, including emission compositions.

Nuclear: Nuclear fuel is another fuel source with low variable cost. However, nuclear power plants have high fixed costs ($4,300-$6,300/kW) and long construction cycles of 10-12 years. Although their pollutant emission is minimal and nuclear is the cleanest form of energy outside of renewable energy, nuclear waste is a dangerous byproduct if improperly handled. Options for safe and long-term storage for nuclear waste in the U.S. remain unclear. The public's fear of nuclear power plants stems largely from the infamous 3 Mile Island scare and more recent heightened terrorism concerns.

Natural Gas: Approximately 40% of the installed power generation capacity in the U.S. utilizes natural gas as a fuel source. Although natural gas does not possess a uniform composition, similar to coal the method of power generation using natural gas is uniform. In other words, whether the power plant is SCGT or a CCGT, the usage of the gas is the same. SCGT plants have low fixed costs (~$500/kW), shorter lead times, and quicker construction cycles (6-9 months). The flexibility of SCGT comes at a cost, however, as these plants are highly inefficient and have brief run-time life cycles and high variable costs. CCGT plants have medium fixed costs (~1,000/kW) and are more efficient with lower variable costs and pollutant emission levels.

Wind: Wind is a clean and free resource. Federal tax credits are available through the end of 2012. The variable cost to run a wind farm is very low; however, the fixed costs are on the higher side ($1,900-$2,400/kW). The strongest wind resource is usually located far from population centers, especially in the Midwestern states. More transmission lines will need to be built to move wind power from the wind farms to the cities. Wind also tends to be strongest during off-peak hours and the capacity factor for new wind turbines averages around 30%. Wind power cannot be stored without batteries and may need backup generation.

Solar: Solar has one of the highest fixed costs ($3,500-$7,000/kW), which is somewhat offset by federal tax credits through the end of 2016. Thermal solar is on the lower end of the cost range and photovoltaic is on the higher end of the range. Solar power also has a very low variable cost, since solar energy is a free and clean resource. Outside of certain areas in the United States (namely the Southwest), solar is not cost effective against other fuel types, since the amount of sunlight is not as strong. At the time of this writing, oversupply of solar equipment has been bringing down the cost of of photovoltaic solar cells.

Exhibit 24 lists some of the pros and cons of the various fuel types.

Exhibit 24: Fuel Pros and Cons

	Pros	Cons	Carbon Output relative to Coal
Coal	Low Variable Cost Abundance of Coal Reserves	High Fixed Cost ($2,200-$4,000/kW) Pollution Long Build Cycle (4-6 years)	100%
Natural Gas (SCGT)	Low Fixed Cost ($450-$500/kW) Short Lead Time (~10 minutes) Quick Build Cycle	Inefficient Short Run Time Volatility in Gas Price	60%
Natural Gas (CCGT)	Moderate Fixed Cost ($850-$1,550/kW) High Efficiency / Low Heat Rate Low Emissions	High Variable Cost Oversupply Volatility in Gas Price	40%
Nuclear	Low Variable Cost Emission Free	Highest Fixed Cost ($4,300-$6,300/kW) Longest Build Cycle (10-12 years) Radioactive Waste	~0%
Wind	Very Low Variable Cost Renewable / Tax Credits	High Fixed Cost ($1,900-$2,400/kW) Strongest Wind Resource During Off-Peak Hours and Far from Population Centers	0%
Solar	Very Low Variable Cost Renewable / Tax Credits	High Fixed Cost ($3,500-$7,000/kW) Solar Resource Strongest in Southwest	0%

Source: Oppenheimer & Co. Inc.

How do the economics of these fuel types compare to one another? Exhibit 25 compares the all-in costs of each fuel type. We assume that each plant is newly constructed and, therefore, still carries a full depreciation schedule. In the all-in cost calculations, we include an estimated cost for carbon emissions but not for other type of pollutant emissions. Our analysis does not include investment tax credits or production tax credits for wind or solar projects, nor does it include the cost of new transmission lines or the occasional need to add a natural gas plant to offset the intermittent nature of these technologies. Fossil fuel plants tend to be built closer to existing transmission lines.

Exhibit 25: All-In Cost of a Newly Built Power Plant by Type of Fuel

Nuclear			**Coal**			**Combined Cycle Gas (CCGT)**		
Typical plant size	1,200	MW	Typical plant size	800	MW	Typical plant size	500	MW
Capacity factor	92%		Capacity factor	85%		Capacity factor	65%	
Volumes	9,671	GWh	Volumes	5,957	GWh	Volumes	2,847	GWh
Construction cost	4,500	/kW	Construction cost	2,400	/kW	Construction cost	1,200	/kW
Depreciation rate	2.5%		Depreciation rate	2.5%		Depreciation rate	2.5%	
% debt	50%		% debt	50%		% debt	50%	
Cost of debt	6%		Cost of debt	6%		Cost of debt	6%	
Return on equity	11%		Return on equity	11%		Return on equity	11%	
Tax rate	35%		Tax rate	35%		Tax rate	35%	
Cost of uranium	$3	/ton	Cost of coal	$54	/ton	Cost of gas	$6	/mcf
Cost of carbon	$0	/MWh	Cost of carbon	$20	/MWh	Cost of carbon	$8	/MWh
Fuel cost	$5	/MWh	Fuel cost	$46	/MWh	Fuel cost	$53	/MWh
O&M	$12	/MWh	O&M	$8	/MWh	O&M	$6	/MWh
Depreciation	$14	/MWh	Depreciation	$8	/MWh	Depreciation	$5	/MWh
Interest	$17	/MWh	Interest	$10	/MWh	Interest	$6	/MWh
Taxes	$17	/MWh	Taxes	$10	/MWh	Taxes	$6	/MWh
Cost of equity	$31	/MWh	Cost of equity	$18	/MWh	Cost of equity	$12	/MWh
All-in cost	**$95**	**/MWh**	**All-in cost**	**$99**	**/MWh**	**All-in cost**	**$88**	**/MWh**
Variable cost	$5	/MWh	Variable cost	$46	/MWh	Variable cost	$53	/MWh

Simple Cycle Gas (SCGT)			**Wind**			**Thermal Solar**		
Typical plant size	120	MW	Typical plant size	50	MW	Typical plant size	10	MW
Capacity factor	10%		Capacity factor	40%		Capacity factor	30%	
Volumes	105	GWh	Volumes	175	GWh	Volumes	26	GWh
Construction cost	500	/kW	Construction cost	2,500	/kW	Construction cost	3,500	/kW
Depreciation rate	2.5%		Depreciation rate	4.0%		Depreciation rate	4.0%	
% debt	50%		% debt	50%		% debt	50%	
Cost of debt	6%		Cost of debt	6%		Cost of debt	6%	
Return on equity	11%		Return on equity	11%		Return on equity	11%	
Tax rate	35%		Tax rate	35%		Tax rate	35%	
Cost of gas	$6	/mcf	Cost of fuel	$0	/MWh	Cost of fuel	$0	/MWh
Cost of carbon	$12	/MWh	Cost of carbon	$0	/MWh	Cost of carbon	$0	/MWh
Fuel cost	$84	/MWh	Fuel cost	$0	/MWh	Fuel cost	$0	/MWh
O&M	$8	/MWh	O&M	$10	/MWh	O&M	$20	/MWh
Depreciation	$14	/MWh	Depreciation	$29	/MWh	Depreciation	$53	/MWh
Interest	$17	/MWh	Interest	$21	/MWh	Interest	$40	/MWh
Taxes	$17	/MWh	Taxes	$21	/MWh	Taxes	$39	/MWh
Cost of equity	$31	/MWh	Cost of equity	$39	/MWh	Cost of equity	$73	/MWh
All-in cost	**$172**	**/MWh**	**All-in cost**	**$120**	**/MWh**	**All-in cost**	**$226**	**/MWh**
Variable cost	$84	/MWh	Variable cost	$0	/MWh	Variable cost	$0	/MWh

Source: Oppenheimer & Co. Inc.; nuclear includes decommissioning provision

A lot has been said about the impact of carbon prices on power prices. In our example in Exhibit 25, we have assumed that carbon is priced at $20 per ton. The rule of thumb is that a dollar of carbon will cost a coal plant $1 per MWh. As Exhibit 26 shows, the exact conversion ratio is that 0.951 tons of carbon is found in one MWh of electricity produced by a coal plant. The exhibit also shows the sensitivity of power prices to carbon and the break-even cost of natural gas needed to compete against a coal plant.

Exhibit 26: Effect of Carbon Regulation on Power Prices from Coal Plants

Assumptions		
Type of Coal	Central Appalachia	
Heat Content	12,500	btu/lb
Sulfur Content	1.20	lb/mmBtu
Price (Q110, FOB)	$ 57.46	/ton
Transportation	$ 12.00	/ton
Sulfur and NO_X	$ 0.10	/lb
Cost of Power - Coal Only	$ 28.10	/MWh
Cost of Sulfur and NO_X	$ 1.52	/MWh
Cost of Power w/o Carbon	$ 29.62	/MWh
Carbon Conversion	0.951	tons/MWh

Sensitivity of Gas Prices to Break Even w/ Coal Plant						
Carbon price ($/ton)	-	10.00	20.00	30.00	40.00	50.00
Cost of Power w/o Carbon	29.62	29.62	29.62	29.62	29.62	29.62
Added Carbon Cost ($/MWh)	-	9.51	19.01	28.52	38.03	47.54
Cost of Power ($/MWh)	29.62	39.13	48.64	58.14	67.65	77.16
Type of Gas System	Break Even Price of Natural Gas					
Steam Turbine	2.71	3.02	3.34	3.65	3.96	4.28
Gas Turbine	2.47	2.71	2.95	3.19	3.42	3.66
Combined Cycle	3.81	4.48	5.15	5.82	6.49	7.17
(price is $ per mcf)						

Source: SNL; Oppenheimer & Co. Inc. estimates

Our analysis shows that every dollar increase in the cost of carbon will allow natural gas to price 2.4 cents to 6.7 cents higher in order for a natural gas plant to break even with a coal plant; the difference in incremental costs is due to the type of gas-fired system. This is more than the effect that a dollar shift on the price of coal affects gas. We expect for each dollar increase in the coal price per ton, the break-even price of natural gas increases by 5 cents. Some studies show that to make a material difference in switching from coal to natural gas, the price of carbon would need to be around $50 per ton. For a combined cycle gas plant, this would lead to an increase of $3.36 per mcf in the break-even price, from $3.81 to $7.17.

TRANSMISSION

Transmission is the backbone of the U.S. electric system, with over 200,000 miles of high-voltage transmission lines (230 kilovolts and greater). Transmission is used to carry electricity over a great distance, allowing for greater reliability and, theoretically, better arbitrage of electricity prices. Voltage is generally increased, or "stepped up," to limit power loss during transmission. In the U.S., transmission lines are regulated at the federal level by Federal Energy Regulatory Commission (FERC) except for Texas. FERC establishes the transmission rates and the utilities recover their investments and operating costs through rate cases at the federal and state levels. The dual jurisdiction over transmission rates often results in conflict and is one of the many reasons the transmission system is fragmented.

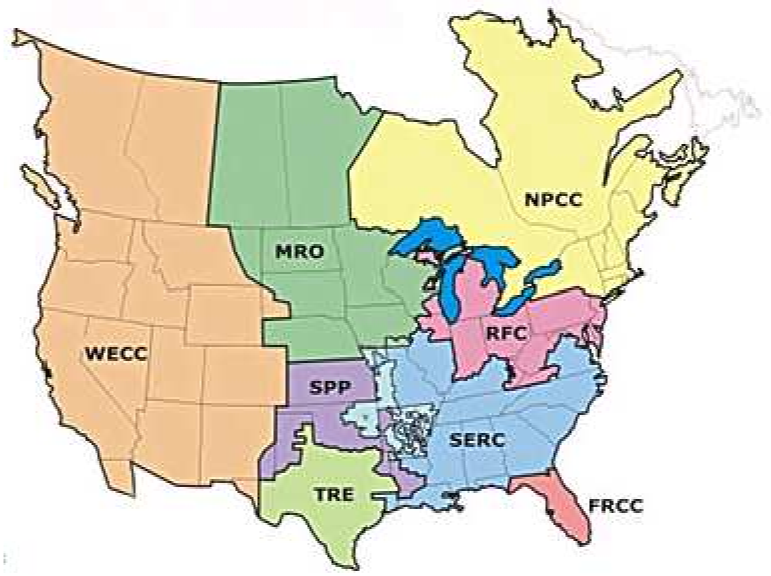
The U.S. transmission system is divided into three power grids:

- East.
- West.
- Texas.

Within these power grids are eight NERC regional power markets:

- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool, RE (SPP)
- Texas Regional Entity (TRE)
- Western Electricity Coordinating Council (WECC)

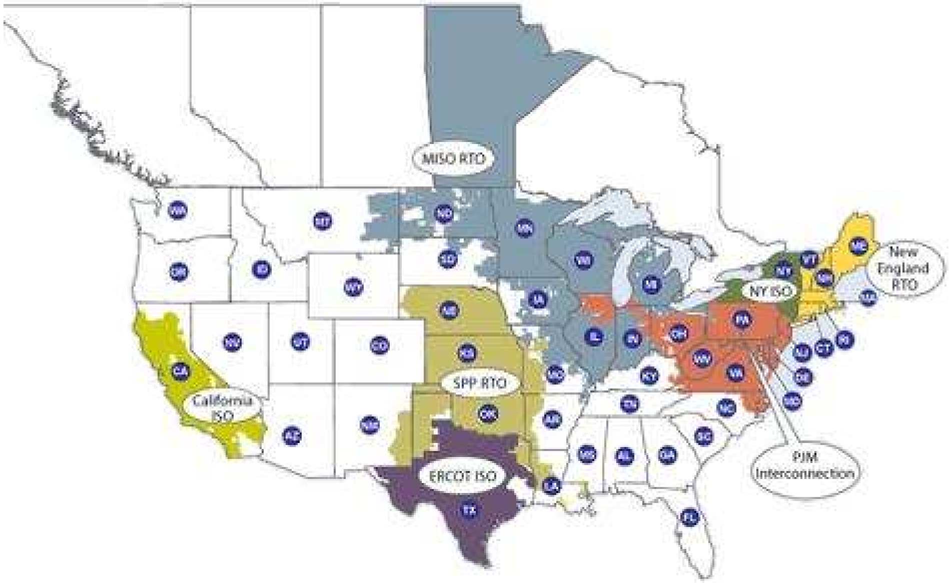
Exhibit 27: Map of NERC Regions



Source: North American Electric Reliability Corporation.

Transmission systems are federally regulated by FERC, as transmission lines can cross state borders. Traditionally, utilities run their own networks, but in some cases Regional Transmission Organizations (RTOs) have been created to manage transmission networks. Some utilities are establishing separate transmission companies to manage long distance transmission projects.

Exhibit 28: Map of FERC RTOs



Source: Federal Energy Regulatory Commission.

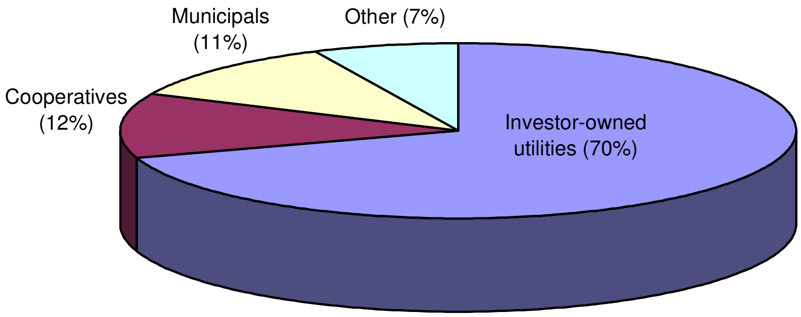
DISTRIBUTION

Distribution networks have lower voltage than transmission networks. After long distance transmission, the voltage is lowered, or “stepped down,” for the electricity to be delivered to the end user. Distribution is the most visible segment in the process of getting electricity to the customer and is subject to state and local regulation.

The distribution segment is the most fragmented part of the power industry. In 2007, there were 212 investor-owned utilities (IOUs) and more than 3,000 municipalities and cooperatives, according to Edison Electric Institute. Despite the large number of participants, the majority of customers are served by IOUs, as shown in Exhibit 29.

Capital investment in the distribution stage is largely tied to customer growth prospects or demographics, although the advent of smart grids is likely to change this relationship (see below). Regulators monitor investments to be included in the rate base. They tend to consider new investments on a short-term basis (less than five years), as legislators often look to uphold the concerns of their constituency, who usually have short-term time horizons.

Exhibit 29: Electricity Distributed by Type of Provider



Source: Edison Electric Institute.

Smart Grid: The Next Frontier in Distribution

A smart grid will be the modernization of both the transmission and distribution systems. The definition of a smart grid is still a bit loose, but broadly speaking, a smart grid system will use new technology to make the electric grid more efficient in getting energy to consumers. In theory, a smart grid is better able to manage supply and demand and should be able to meet increased demand without adding new generation. The real-time two-way communication between the consumer and utility is supposed to allow consumers to better monitor energy use and cost. A smart grid is expected to be intelligent and capable of working autonomously for fast resolutions to reduce interruptions and disturbances to the flow of power. However when some utilities and states refer to a smart grid, they mean the upgrades to infrastructure that are needed to make the system smart-grid ready. In our view, two key requirements for the success of smart grids are the development and integration of enabling software, and, ultimately, the pace at which consumers adopt the new technology.

RETAILING

The marketing of power and related services is called retailing. Retailing is the acquisition of electricity from a producer or wholesaler that is then resold to customers. Retailing does not involve any ownership of the transmission and distribution wire systems. The unregulated retailers are called Energy Service Providers (ESPs). Gexa Energy was such a company before it was acquired by FPL Group a few years ago. Electricity retailing should not be confused with the retail customers of integrated utilities. The latter are considered native customers. These customers are subject to regulated rates, although they can choose an ESP in certain markets. The utility remains the ultimate transporter of the commodity and gets a regulated rate for that.

Services offered by retailers include power procurement, ancillary service and risk management. In order to be profitable, therefore, it is critical that an ESP procure power at a reasonable price to resell and not expose itself to the fluctuations in the marketplace. Little capital is needed to start up an ESP and other barriers to entry are relatively low, making retailing the most competitive component of the electricity chain.

Due to the hybrid nature of the electric market, many markets that introduced competition also mandated that incumbent utilities offer a capped price to customers that did not switch. Because of high commodity prices, the standard offer was often the best price available and customers did not switch, stymieing the development of a robust competitive market. Lower commodity and power prices should encourage customers to shop around for ESPs.

Regulatory Overview

Why Is the Industry Regulated?

Electric utilities are highly regulated for a number of reasons. First, the costs—and the difficulty—of building a competitive distribution and/or transmission system are typically not worth the duplication. There are a few places in the United States where two sets of distribution wires share one street, such as certain neighborhoods of Cleveland, but most communities would rather see only one set of wires around their homes. Second, certain projects are best funded through public policy. For example, the market is less likely to support building a new nuclear plant due to the long lag between capital invested and capital returned. Third, left to its own devices, the price of electricity is very volatile, given the lack of technology that can store (inventory) power. Certain states are not comfortable with large swings in electricity prices and how they can impact residential customers. The natural response, then, is to regulate prices. This is more easily done when the assets are regulated. Finally, many states believe that the availability of electricity to all customers should be mandatory; electricity is viewed as an essential component of modern society. The drawback of being regulated—aside from inefficiencies, real or perceived—is that regulators might act as though they own the assets. A common misconception among consumer groups is that because ratepayers pay for power they can control how the assets is used. However, it is worth remembering that the capital at risk comes from shareholders and bondholders. And, ultimately, the shareholders are the owners of these assets.

Regulatory Bodies

State Commissions

Part of what makes it so difficult to follow the utility industry is that each state approaches regulation differently. There are commissions in all states, as well in the District of Columbia, Puerto Rico, and the Virgin Islands. (We provide a list of all the commissions in the Appendix.) Most commissions are referred as a Public Utility Commission (PUC) or Public Service Commission (PSC), although they can also be known as a Board or Corporation Commission. Their primary function is to regulate utility activities, by setting appropriate rates that balance the needs of all stakeholders. Virtual any new utility project must be approved by the commission, if utilities want to increase their chances of recovering their investment.

In most cases, commissioners are nominated by the governor of the state. A dozen states elect their commissioners, particularly in the Southeast, Southwest, and the Great Plains. Three to five commissioners sit on the commission, with terms that lasts four to six years; only North Carolina allows terms greater than six years (eight). The commission is generally headed by a chairman or chairperson—California calls its chairman “President”—who is sometimes nominated by the governor, sometimes elected by fellow commissioners.

Within the commissions, there are generally two main sub-groups: the commissioners and the staffers. In some cases, each commissioner can have his/her own staff, separate from the public staff. Some staff members specialize in certain topics. The staff is often assigned the role of advocating for consumers, particularly residential consumers, who are often not represented during hearings. Staff is also free to enter into settlement discussions with the utility, in concert with other interveners.

Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) is responsible for rules and regulations tied to interstate energy matters. These include long-distance natural gas pipelines and interstate transmission lines, including reliability and wholesale price issues. Furthermore, the FERC is charged with monitoring affiliate transactions, investigating violations and imposing penalties, and interstate mergers.

Nuclear Regulatory Commission

The Nuclear Regulatory Commission (NRC) is charged with licensing, monitoring, and investigating all commercial nuclear activities. Specifically, it creates and enforces regulations for nuclear licensees; oversees operating and safety policies of nuclear plants; performs inspections of nuclear operations; investigates allegations; enforces NRC policies; and imposes sanctions. The NRC also regulates the design approval, licensing, licensing renewal, and decommissioning of nuclear plants.

Other Regulatory Bodies (EPA/SEC/DOJ)

The Environmental Protection Agency (EPA) was created in 1970 to protect water, air, and land from pollutants. The agency sets national environmental standards and develops and implements environmental laws. It has the authority to monitor compliance and issue sanctions when standards are not met. The pollutants that fall under EPA authority that impact the electric utility industry include sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury, and, since a 2007 Supreme Court decision, greenhouse gases.

Both the Securities and Exchange Commission (SEC) and the Department of Energy (DOE) can affect the electric sector during mergers and acquisitions, although the SEC was in charge of regulating utility holding companies prior to 2005, when the 1937 Public Utility Holding Company Act (PUHCA) was repealed. It is unusual for either agency to challenge a utility merger given how fragmented the electric utility industry is. Furthermore, mergers among regulated utilities are also scrutinized by the states, which tend to set a higher burden of proof that a transaction is in the best interest of ratepayers. Many a utility merger has failed due to lack of support from state regulators.

Rate Cases 101

The state utility commission’s principal vehicle to regulate a utility is through hearing a rate case, particularly in the event that a change in rates is requested. The goal of a rate case is to set reasonable rates to allow a utility to earn a fair return for its shareholders while at the same time providing reliable service. Until recently rate cases were the most effective way to adjust rates according to the level of investment made by the utility. In some cases—particularly in those days—rates would be adjusted upward to reflect the large capital investment program that the industry was undertaking. In other cases, the pace of investment might lag increased usage, which would effectively boost returns, enabling utilities to earn above their allowed return (which could prompt the commission to call for a new rate case). The invested capital of a utility is called its “rate base.”

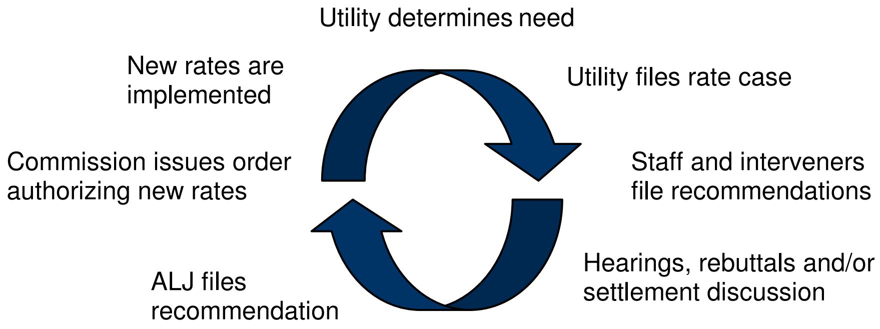
Rate case proceedings share many similarities with the United States legal system. A rate case is prepared and filed with the commission. Hearings and evidence are presented, during which testimony is given. At the end, similar to a judge, the commission reaches a decision that tries to objectively take into account all aspects of the case. Sometimes, the parties involved reach a compromise position called a settlement, which needs to be approved by the commission to be valid. Unlike a court case where typically two parties oppose one another, a rate case attracts a number of interveners, including the utility, the staff of the commission, industrial groups, and consumer advocates. In some cases, an administrative law judge also provides an opinion. While it is always important to follow what different interveners have to say, a lot of attention is spent on 1) what the utility files and whatever adjustments might follow, 2) what the staff recommends, and 3) what the ALJ proposes to the commission. Typically—although not necessarily—the filings by the utility company and the staff represent the two book ends, with the commission’s findings coming in somewhere in between.

The timing of rate cases is not always perfect science. Not only does each state have its own process, but utilities within each state might be under different schedules. In many cases, states have historically set up a mandatory schedule for filing rate cases. This allows the commission to determine whether utilities are over-earning. It also allows the utilities to adjust their rates to reflect their costs. In some cases, utilities are not required to file a rate case until they believe that rates are not keeping up with their operating and capital costs. There is always a possibility that a utility could be forced into a rate case. This might happen when interveners lobby for a rate case or the commission believes that the utility is simply over-earning. Most settlements specify how long a utility can stay out of a rate case.

One of the biggest problems with rate cases is the issue of regulatory lag. Let’s assume that Utility A filed a rate case on December 31st, 2005, asking for a 12% return on equity (ROE) on a $10 billion rate base using 50% equity financing. Say the commission grants an 11% ROE on June 30th, 2006, 18 months after the initial filing. While eighteen months is longer than typical—six months to a year is more the norm—we are exaggerating to make a point. At 11% ROE, 50% equity ratio, and $10 billion of rate base, the net income would be $550 million (more on that later). However, let's assume that the rate base as of June 30th, 2006 had grown to $12 billion. The effective ROE is now $550 million of net income divided by $6 billion of equity, or 9.2%. There are ways to reduce this regulatory lag, like implementing interim rates shortly after the company's filing or adjusting rates based on incurred investment without waiting for the next rate case.

Each state approaches the issue of regulatory lag differently. While the actual process of a rate case can vary from state to state, we have tried to capture in Exhibit 30 a typical rate case cycle. From the time the utility files a rate case, there can be settlement discussions, but those discussions start in earnest after the staff recommendation. Of course, settlement discussions tend to go nowhere if the company and the staff start too far apart. A rate settlement remains the best way to determine new rates and is typically approved by the commission.

Exhibit 30: Typical Rate Case Cycle


Utility determines need
Utility files rate case
Staff and interveners file recommendations
Hearings, rebuttals and/or settlement discussion
ALJ files recommendation
Commission issues order authorizing new rates
New rates are implemented

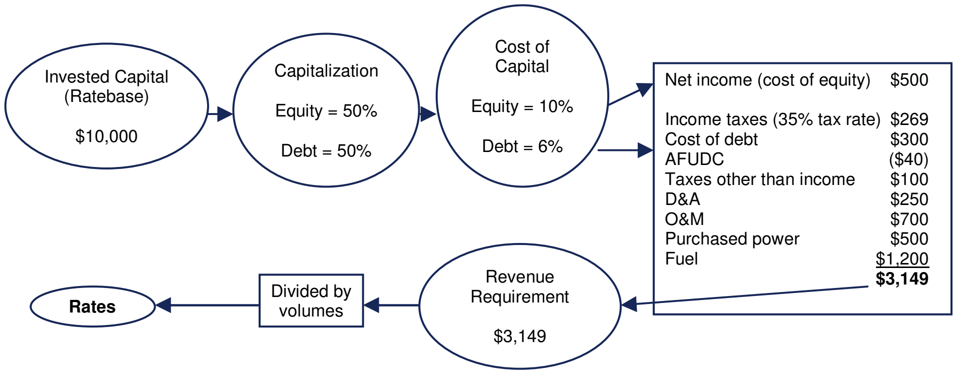
Source: Oppenheimer & Co. Inc.

So far, our comments about rate cases have centered on invested capital, but when utilities file rate cases, they are also seeking to recover their prudently incurred operational expenses. While the latter should be pass-through (i.e., the utility does not earn a return on expenses), rates still need to be adjusted to incorporate any increases. Examples of operating expenses are fuel costs, purchased power costs, material, labor (including pension costs), and maintenance. In some cases, the commission might determine that certain expenses were improperly incurred. Even though fuel costs are typically a pass-through item, the commission can decide that the cost of fuel was imprudent and disallow it. Utilities for the most part continually seek the approval from their commission to make sure that costs will be recovered. Typically, the bulk of a utility's operating expenses are recovered.

The ability to cover operational costs is important, but the bulk of the headline news focuses on return of capital, particularly return on equity. As mentioned earlier, utilities are allowed a "fair" return on their rate base. Generally speaking the rate base is the utility's assets, with some adjustments such as deferred taxes. All rate base calculations include property, plant, and equipment, as well as other assets used to serve ratepayers, but the exact formula varies by state. Most of the time, utilities must show their commissions that the plants are "used and useful" before they can be included in rate base. This ensures that current ratepayers pay for current assets rather than paying for future assets. In some cases, such an approach can lead to regulatory lag problems, as large multi-year power plants are not included in rate base until they are completed. To deal with those issues, the industry uses CWIP (construction work in progress) and AFUDC (allowance for funds used during construction) accounting, which we will cover in more detail later.

Exhibit 31 shows a sample rate tariff calculation and how rates are derived from rate base and operational expenses.

Exhibit 31: Example of Rate Calculation (in millions)



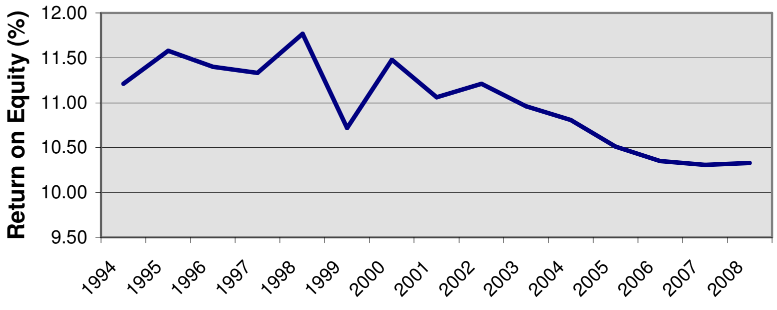
Net income (cost of equity)	$500
Income taxes (35% tax rate)	$269
Cost of debt	$300
AFUDC	($40)
Taxes other than income	$100
D&A	$250
O&M	$700
Purchased power	$500
Fuel	$1,200
	$3,149

Source: Oppenheimer & Co. Inc.

Note the seemingly high level of debt in Exhibit 31. Those unfamiliar with the utility space may find 50% debt to cap alarming, as most industries do not feature such a heavy debt burden. This example, however, is very typical. The typical balance sheet of a utility will have an equity ratio of 47%-53% with extremes on the strong side at 60% and on the weak side, 40%. The ability to have a highly levered balance sheet is predicated on the predictability of earnings recovery that is built into rate cases. Furthermore, because the cost of debt is lower than the cost of equity, regulators prefer more debt. This brings the rating agencies into the equation, as a ratings downgrade becomes a risk such that utilities work to balance acceptable ratings with debt levels. In fact, regulators typically focus more on the view of the rating agencies than shareholders' perspectives. This is also why utility management interacts with the agencies more than one would expect.

Recently, ROEs have trended downward and have kept in a range of 10.3% to 12.8%, as seen in Exhibit 32. ROEs and the capital structure are determined on a case-by-case basis by the commission and play a primary role in determining the fairness of the rate case.

Exhibit 32: Average Awarded Electric Utility ROE



Source: SNL

Once we know the approved rate base, equity ratio, and ROE, the net income can easily be derived. In the example from Exhibit 31, the net income is calculated to be $500 million ($10 billion x 50% x 10%). Investors should be thinking that net income is another cost that needs to be recovered when deriving revenues. Once the revenue requirement is reached by summing the various costs, the requirement number is divided by sales volume to calculate tariffs. Residential customers generally bear higher rates than commercial and industrial users.

The rate case that was just described is known as a General Rate Case (GRC) and is typically the most detailed and time-consuming kind of case. There is another type of cost recovery mechanism that commissions allow that is less time consuming and cumbersome. It is called a rider. It is rate mechanism which adjusts rates without a full case. Riders are submitted either with a larger general rate case or on a standalone basis. They are usually requested to offset additional costs, with the most common being for fuel and purchased power adjustment clauses, storm recovery, environmental cost recovery, energy conservation, or weather adjustments for natural gas utilities (Exhibit 33 lists a few examples of riders). Recently, more states have started to allow Construction Work in Progress (CWIP) costs to be included in rate base. This reduces the lag time that is created by the long-term process of building new plants. This mechanism allows recovery on investment before a project is complete. CWIP mechanisms are usually brought as a standalone case. The benefit to both the utility and consumer of the CWIP rider is that it keeps customers' bills in line with costs of providing power—essentially reducing regulatory lag and large, one-time increases. For a utility, riders provide a better guarantee of invested capital recovery.

Exhibit 33: Rate Making Mechanisms: Examples of Riders

Fuel Clause	Pass through for fuel costs needed to generate power.
Environmental Cost Recovery	Surcharge for recovery of qualified environmental compliance costs.
Energy Conservation	Surcharge for recovery of efficiency and conservation program costs.
Storm Damage Recovery	Surcharge added to customer bill to recoup the expenses related to outages caused by hurricanes or storms.
Stranded Costs	Costs associated with the deregulation of a state's generation market.

Source: Oppenheimer & Co. Inc.

Minimizing regulatory lag is an important issue for utilities. Aside from the use of riders, using a forward test year in place of a historical test year can be used to reduce the lag. A forward test year uses projected costs instead of historical costs in determining the rate base. A historical test year is usually the prior 12 months. Some test years can be a blend of historical and projected future months. As one can see, a lag can build up with a historical test year.

Understanding AFUDC and CWIP

As we have discussed, utilities are quite capital intensive. Maintaining the transmission and distribution systems as well as the power plants requires a lot of capital. Building new plants to meet demand not only requires large amounts as well, but also creates a long lag time in cost recovery as it takes many years to build a power plant—more than 10 years for a nuclear plant. An entire business cycle can take place during the construction of a nuclear plant. Usually, a utility will not earn a return on the upkeep or buildout of its power structure until the facility gets approved by the state commission and placed into rate base. There are two accounting mechanisms that have been adopted to offset some of the financing costs: Allowance for Funds Used During Construction (AFUDC) and Construction Work in Progress (CWIP).

CWIP is an asset account in the Property, Plant, and Equipment section of the balance sheet. As its name implies, it tracks projects that are under construction but not yet placed in service. Both debt and equity funds are credited to the income statement during the construction process as AFUDC. The capitalized financing costs during construction are depreciated as part of the investment.

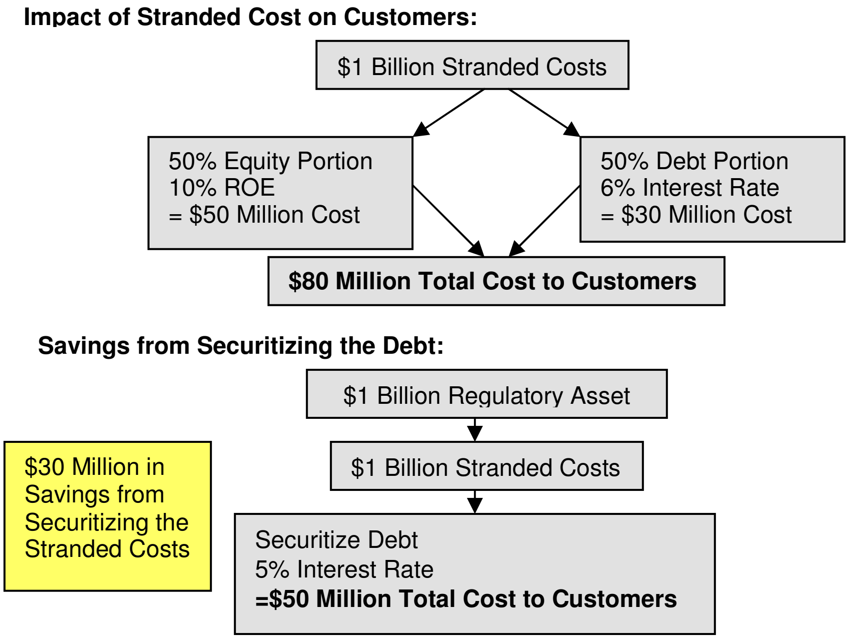
Note that this is somewhat misleading as there is no cash to back up the "earnings" on the income statement that are produced using the AFUDC account. This is because the CWIP has not been placed into rate base and the cost has not been passed through to the consumer. But for utilities that do not wish to carry a heavy debt load on the balance sheet (possibly for ratings reasons), it is important for the utility to rate base the CWIP. As mentioned earlier, this benefits both the consumer and the utility. It is done through a rate mechanism and more states have started to allow this. One compromise by states that have not allowed the utilities to rate base the CWIP is to allow the utility to recover the financing costs in cash. This prevents the interest on interest that can occur with very long projects that create lag time build-up.

Stranded Assets, Regulatory Assets and Securitization

Capital investments, purchased power agreements, fuel supply contracts, and other regulatory assets that are determined to not have the ability to recover costs through the sale of electricity are called stranded assets. This inability occurs when the net present value of the future cash flows is less than their current market value. In the opinion of companies and many regulators, this exclusion violates the regulatory compact that states that investments that are deemed prudent should be recoverable through utility rates. This was a big issue when a number of states were switching to a competitive model roughly 10 to 15 years ago.

When a stranded cost or stranded asset occurs, it may be reclassified as a regulatory asset on the balance sheet. The purpose of this is to allow the utility to maintain it as an "asset" in its rate base. The regulatory asset can be used to recover storm damage or to phase in fuel costs during high power price periods. The purpose is to keep the lag created by the extra expense off the income statement as it is shifted to the balance sheet with the presumption that it will be recovered later.

Exhibit 34: Example of Benefits of Securitizing Stranded Costs


Impact of Stranded Cost on Customers:
$1 Billion Stranded Costs
50% Equity Portion
10% ROE
= $50 Million Cost
50% Debt Portion
6% Interest Rate
= $30 Million Cost
$80 Million Total Cost to Customers
Savings from Securitizing the Debt:
$1 Billion Regulatory Asset
$1 Billion Stranded Costs
$30 Million in Savings from Securitizing the Stranded Costs
Securitize Debt
5% Interest Rate
=$50 Million Total Cost to Customers

Source: Oppenheimer & Co. Inc.

Recovering the stranded costs is similar to a regular rate base recovery and is shown in the top of Exhibit 34. The relevant capital structure is the one that was determined by the state commission in the last rate case. Usually, the utility bill will have a line item dedicated to the regulatory asset and this is treated as a surcharge.

One way to minimize the cost to customers while still recovering the costs to the utility on a cash basis is to securitize the asset. Any asset that has a steady cash flow can be securitized. Regulatory assets are no different and make it quite simple, since the customer's utility bill will already have a line item dedicated to the asset. In the bottom half of Exhibit 34, an example is shown of the savings provided to customers. In this scenario, with $1 billion in regulatory assets, it is likely that the regulators will approve the securitization of the debt with a 5% coupon. An AAA rating will probably be given to the debt, as it is backed by the receivables, implying almost no default risk. The utility will use the cash proceeds to pay down the higher interest debt and to repurchase shares. The customer is better off, since it is paying 5% interest as opposed to the blended 8% cost of capital it was paying before.

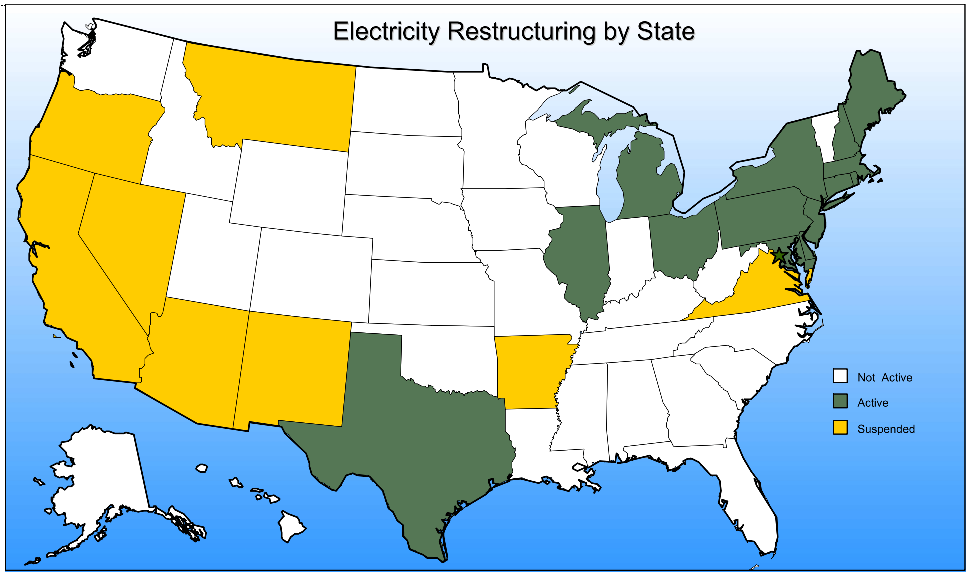
But securitizing regulatory assets raises some minor issues. No return can be earned on the regulatory assets, which leads to lower earnings. Furthermore, the principal payments are booked in the amortization line while the interest paid is recognized as interest expense. The collection of funds to service the principal and interest is recognized as revenue. This can distort EBITDA in two ways. First EBITDA is overstated by the principal amount because the amortization is a cash item and doesn't act like normal amortization. Secondly, the revenue collected to cover the securitization is effectively covering an off-balance sheet item; it has no impact on net income as it is offset by higher amortization and higher interest costs. We believe that EBITDA should be further adjusted down for this. One way to mitigate the first issue is to buy back shares with the proceeds. This will offset lower earnings.

Deregulation

Deregulation: A Country Polarized

Since 1993, the electric utility has undergone a massive operational and financial transformation. After a rather successful transition in the early 1990s to competition of the natural gas interstate pipeline industry, regulators and politicians in a number of high cost states started to implement deregulation plans for the electric utility industry. Naturally, states with low power cost structures were not as interested in pursuing deregulation. Furthermore states have primary jurisdiction over electric utilities and state priorities do not always match federal mandates for competitive power markets.

Exhibit 35: High-Cost Areas Like Northeast and Texas are Deregulated



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re
deregulated may only have one element of the electric chain deregulated (generation and/or retail). In the “suspended” states (yellow), assets have either been returned to the utility or the deregulation process was never completed.

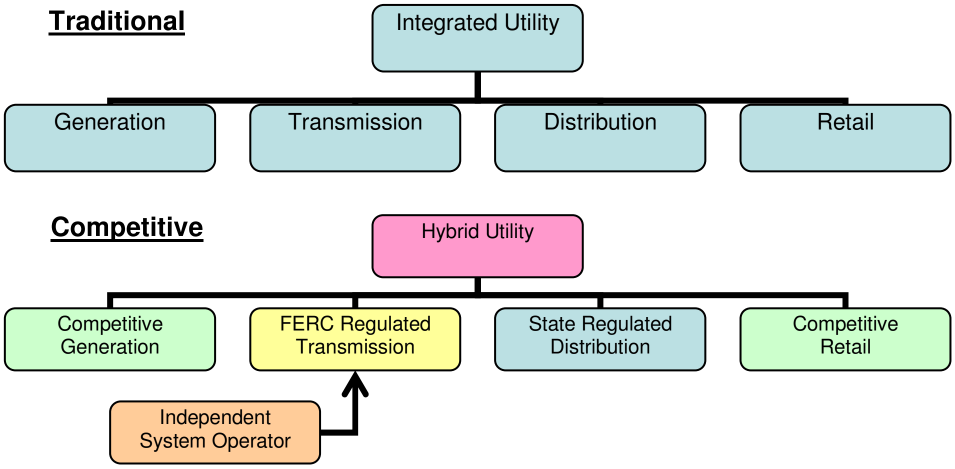
In this primer we do not go through the historical and political reasons for deregulation or discuss its merits, as it is still unclear whether deregulation has been/will be positive or negative. Rather, we explain the operational and financial differences that exist between deregulation and regulation.

Difference Between Regulated and Competitive Utilities

In Exhibit 36, we have laid out the main differences between a regulated (traditional) and a competitive utility model. As should be expected, in the traditional model the wires or pipes part of the business remains regulated: it makes little economic sense to create competing infrastructure to deliver electricity or natural gas to end-user sites. In the telecommunications realm, in contrast, providers can sell media content at healthy (or at least competitive) margins, which can encourage the building of alternative networks, whether they be fiber or wireless. But the delivery of energy does not offer high margins on the product itself yet, although the advent of distributed generation could change that.

Not all elements of a competitive model are necessarily deregulated. As shown in the hybrid example in Exhibit 36, the elements that are more likely to be deregulated are the generation assets (upstream) and retail customers. The United Kingdom goes one step further and has unbundled the installation and management of meters. Some states have deregulated generation but effectively not retail. Others, like Michigan, have deregulated retail, but regulated generation. The best example of competitive markets resides in Texas, where the local T&D companies do not even bill the end-users. Until this year, the incumbent retail provider for the Houston market was Reliant Energy (owned at the time by RRI Energy); the T&D company still is CenterPoint Energy, and the largest generator for Houston still is NRG Energy. Since then, NRG has bought Reliant Energy from RRI Energy. The NRG-Reliant transaction highlights a key point regarding the structure of deregulation. There must a clear separation between the generator and the retail provider, i.e., transmission must be functionally separate. Otherwise certain generation assets can be favored and the customer ultimately loses.

Exhibit 36: Traditional versus Competitive Utility Model



Source: Oppenheimer & Co. Inc.

Assuming there are no economically inefficient activities in a given market, the biggest benefit of competition stems from the dispatch by power plants, i.e., it ensures that customers pay for power plants that dispatch power but not for those that do not (except for certain reliability products). In Exhibit 37, the Independent System Operator plays that role. Our next section covers the mechanism that dictates the price of electricity in competitive markets.

Marginal Cost Is King

There are two major differences between a regulated and an unregulated model from a return on capital standpoint. First, if a utility is subject to regulation, its return is more or less fixed, whereas an unregulated generator can earn whatever the market is willing to pay. Second, a regulated utility has a higher certainty of capital recovery, whereas an unregulated generator's invested capital might in theory never be recovered. Under regulation, the utility dispatches power according to need but charges its all-in cost of generation, which includes all non-cash costs (depreciation mainly). Regulated utilities still dispatch electricity according to the cheapest variable cost (mostly driven by fuel cost), but they charge fixed costs too – including cost of equity. This full recovery model does not apply to unregulated generators, as we will cover in the following paragraphs.

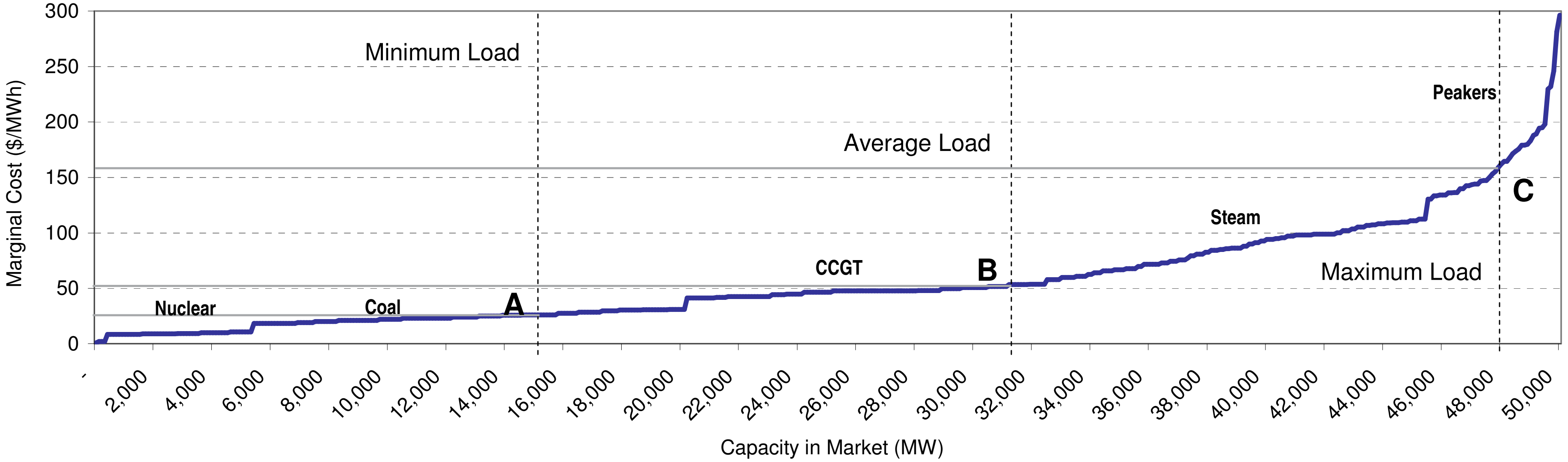
Unregulated power markets are very similar to most competitive markets. The lowest cost producer dispatches power often, if available, whereas the higher cost producer has few opportunities to sell power in the market. The most costly plant to dispatch in the market is theoretically the cheapest one available to dispatch among those plants that are sitting idle. As a result, it is important to identify the cost of that marginal plant, mainly because it sets the price of power for the rest of the market. As we look at the dispatch curve in Exhibit 37 on the next page, we note that at minimum load (about 15,000 MW needed out of 50,000 MW), the marginal cost is about $28. This sets the marginal price, thus allowing all the plants on the left of the demand line (line A) to receive $28. The same exercise can be carried out for demand lines B and C, where the marginal price is about $55 and $165 per MWh, respectively.

It is worth noting that unlike other sectors where there is little difference between the marginal cost of production facilities, the power sector exhibits big differences in marginal cost. To illustrate this point, we have annotated Exhibit 37 with the type of power technology or fuel used. For example, the first 300 MW (which we have not described in the chart) is powered by hydro, wind, and solar. The next "stack" – from 300 MW to 5,300 MW – is dominated by nuclear. We have represented steam-generated coal plants in our example as spanning from 5,300 MW to 20,000 MW. Next on the dispatch curve are 12,600 MW of combined-cycle gas turbine plants (see section on Generation starting on page 13 for more details on these plants). The last two stacks are gas-fired steam generators (from 32,600 MW to 45,400 MW) and peakers, which are typically run using natural gas or oil. Of course, in the real world, the stacks are not as clearly defined, especially when natural gas drops below $5 per mcf.

As would be expected, demand and supply influence the dispatch curve. As demand grows, lines A, B, and C move to the right, causing the intersection point with the dispatch curve to move up. This causes the marginal cost to move up too. This is called "moving up" the dispatch curve. The converse holds true too. As demand shrinks, lines A, B, and C move down the dispatch curve, causing the marginal power cost to come down. From a supply point of view, the addition of new supply in the market without a corresponding increase in demand affects the plants located to the right (higher marginal cost) of the incremental plants. Likewise, retired power plants will shift the dispatch curve to the left, starting from where those plants were located.

The third main factor that shapes the dispatch curve is the marginal fuel cost. Natural gas is often the fuel used by the marginal plant. It is therefore very common for power analysts to use natural gas as a proxy for power prices. As a result, higher natural gas prices are often described as positive for power markets. This is often confusing to neophytes, who correctly assume that since natural gas is a cost, any increase in a cost of good sold does not seem to be a good thing. However, because about 70% of the electricity produced in the United States is from either coal-fired or nuclear-fired power plants and natural gas-fired plants set the marginal price in most markets, a rise in the price of natural gas prices will lead to a rise of the marginal cost of power without raising the cost of a coal or nuclear facility. As an example, let's assume that the variable cost of a coal plant is $25. Let's also assume that natural gas is priced at $5 per mcf. A CCGT is dispatching power at $35 per MWh, thus setting the price for the output for the coal plant at $35 too. This gives the coal plant a $10 per MWh gross margin. If natural prices move up to $7, the CCGT plant will produce electricity at $49, giving the coal plant a $24 gross margin, all else being equal. As natural gas prices increase by $2, the coal plant increases its margin by $14.

Exhibit 37: Dispatch Curve Drives Economics of Unregulated Generation Markets



Source: Oppenheimer & Co. Inc.

There are a number of benefits of using natural gas as a proxy for power prices. First, the market for natural gas is very liquid, transparent, and more or less nationwide (adjusting for the nominal geographic price differences). Second, given that most electricity markets are driven by a gas-fired plant on the margin, it becomes relatively easy to determine the pricing direction of those markets. Furthermore, when one compares the forward curve for power prices relative to the natural gas forward curve, one can derive a new dispatch curve based on the marginal heat rate.

The heat rate of a plant indicates how many units of energy (expressed in British Thermal Units, or Btu) it takes to produce one kilowatt-hour (kWh). Typically, the most efficient natural gas plants – the combined cycle gas turbines – have a 7,000 heat rate, which means that it takes 7,000 Btu of natural gas for them to generate one kWh. Naturally, a 10,000 heat plant will take 10,000 Btu to produce one kWh; the higher the heat rate, the less efficient the plant.

The beauty of the use of heat rates is that one mcf (thousand cubic foot) of natural gas is equal to one mmbtu (a million Btu). It leads to a very elegant equation: once an analyst knows the heat rate of a gas plant and the cost of gas, he/she can derive the cost to produce a MWh (megawatt-hour). For example an 8,000 heat rate gas plant will produce electricity at an energy cost of $40 per MWh, if the cost of natural gas is $5 per mcf ($40=$5*8,000/1,000).

Of course, the heat rate is not the only determinant of prices. Coal plants typically have heat rates north of 10,000, an indication of how inefficient they are relative to modern natural gas combined-cycle gas turbines. However, the cost of natural gas per mmbtu is typically much higher than the cost of coal per mmbtu. On an mmbtu basis, coal can sell for about $1.50-$2.50. Even if the efficiency of a coal plant is as poor as a 12,000 heat rate, the marginal cost to produce electricity would be $18-$30 per MWh. Natural gas prices would have to stay below $4.25 per mmbtu (or mcf) to allow a CCGT plant to be competitive.

Time of use is another component of pricing that we will focus on in this primer. As shown in Exhibit 37, the cost of electricity at maximum load is much higher than the cost at minimum load. There are essentially two pricing periods considered in the power market: on-peak and off-peak. Peak pricing is often quoted in the form of 5x16 pricing (16 hours a day Monday through Friday); off-peak occurs during the remaining 88 hours in the week. Total cost, or “round-the-clock,” pricing can simplistically be calculated using a weighted average of on-peak and off-peak pricing. A customer’s “full requirements” contract combines round-the-clock energy prices with any additional reliability services, capacity payments, or even credit risks. It is important that investors make sure that they know which quote they are looking at, as a full requirements contract can easily add $20-$30 per MWh to the overall cost of just producing electricity.

The final measure that is often used in the unregulated power market, especially when discussing the independent power producers, is the spark spread. Essentially the spark spread is the gross margin of a natural gas plant (revenue minus cost of goods sold) on an energy-basis. It does not take into account auxiliary revenues. For example, if the market price is $80 and it costs $56 to produce power from a CCGT, then the spark spread is $24. Typically, a standard measure of market spark spread is to use a 7,000 heat rate plant as a benchmark. Investors can refer to the market spark spread as the spot price for electricity minus the spot price for natural gas multiplied by the standard 7,000 heat rate that we mentioned earlier. In a market where the spot price for electricity is $45 per MWh and the spot price for natural gas is $5 per mcf, the market spot price will be $10 per MWh. Substitute the standard 7,000 heat rate with the specific heat rate of a gas-fired plant and one arrives at the plant’s spark spread relative to a spot price.

Carbon Costs

Natural sources of carbon dioxide (CO_2) occur, but when in balance, total carbon dioxide emissions and removals are roughly equal. However, numerous reports recently have concluded that human activities including the combustion of fossil fuels to generate electricity have increased CO_2 concentrations in the atmosphere. According to these reports, in 2007, global atmospheric concentrations of CO_2 were 36% higher than before the Industrial Revolution. Many scientists believe that the additional greenhouse gases in the earth's atmosphere are changing the amount of radiation coming into and leaving the atmosphere, likely contributing to climate change.

In Europe, the European Union Emission Trading System (EUETS) commenced operation in 2005 in response to the Kyoto Protocol to offer carbon allowance trading and incentivize emissions reductions. Each allowance (permit) represents one ton of carbon dioxide equivalent. The European Union is using a cap-and-trade system where an overall limit, or "cap," is set on the number of allowances to issue. Companies are allowed to trade permits among themselves to meet the requirement at the end of the year. Companies in heavily polluting industries are required to have allowances for each ton of greenhouse gas that is produced. To neutralize annual variation due to extreme weather events, emission allowances can be used at any time within the trading period, but they expire when the trading period ends. Trading, in theory, allows for emissions reductions to occur in the most efficient manner and incentivizes companies to reduce emissions and sell excess allowances. In the first trading period (2005 to 2007) most allowances were allocated for free and in the second trading period (2008-2012) a majority of the carbon allowances will still be allocated for free, although somewhat more will be auctioned. Starting in 2013 with the third trading period (2013-2020), more than half of the allowances will be auctioned and the emissions cap will decline annually to reach a 21% reduction in 2020 from the 2005 level. No allowances will be allocated free of charge for electricity production, with only limited and temporary options to deviate from this rule. Carbon pricing has yet to set up at the federal level in the United States, at the time of this primer.

A carbon offset is an instrument used toward reducing greenhouse gas emissions. Carbon offsets are measured in metric tons of carbon dioxide-equivalent (CO_2e) where one carbon offset represents the reduction of one metric ton of carbon dioxide. Carbon offset projects include renewable energy and energy efficiency.

Renewable Tax Credits

The United States is offering production and investment corporate tax credits for qualifying renewable energy projects. The Renewable Energy Production Tax Credit (PTC) is based on the amount of renewable energy produced by the project, while the Business Energy Investment Tax Credit (ITC) is based on the amount of the qualifying investment in the renewable project. The American Recovery and Reinvestment Act of 2009 renewed the PTC and offered the option to take the ITC or a cash grant in place of the ITC.

New landfill gas, wind, biomass, hydroelectric, geothermal electric and municipal solid waste projects are eligible for the PTC, which generally applies to the first 10 years of operation and is claimed every year of the period.

Exhibit 38: Production Tax Credit Eligibility

Resource	In-Service Deadline	Credit
Wind	December 31, 2012	2.1¢/kWh
Closed-Loop Biomass	December 31, 2013	2.1¢/kWh
Open-Loop biomass	December 31, 2013	1.1¢/kWh
Geothermal Energy	December 31, 2013	2.1¢/kWh
Landfill Gas	December 31, 2013	1.1¢/kWh
Municipal Solid Waste	December 31, 2013	1.1¢/kWh
Qualified Hydroelectric	December 31, 2013	1.1¢/kWh
Marine and Hydrokinetic (>150 kW)	December 31, 2013	1.1¢/kWh

Source: Database of State Incentives for Renewables & Efficiency.

Investment tax credits were already available for select renewable projects, but the American Recovery and Reinvestment Act (ARRA) of 2009 expanded the range of qualifying facilities to include wind, biomass, geothermal, landfill gas, trash, qualified hydropower, marine and hydrokinetic facilities. With the ITC, the entire tax credit is claimed in the year the facility is placed in service and there is no need to sell electricity in order to generate the credit. Qualified property must be placed in service before the credit termination date to receive the ITC. The credit termination dates are listed in Exhibit 39 on the next page.

In lieu of the investment tax credit, companies may opt for a cash grant. The amount of the grant is equal to the credit under the ITC, but grant applications must be submitted by October 1, 2011. Payment of the grant will be made within 60 days of the grant application or the date the property is placed in service, whichever is later. Projects must be placed in service by the credit termination dates. Wind projects must be under construction by the end of 2010 and solar projects must be under construction by the end of 2012.

Exhibit 39: Investment Tax Credit Eligibility

Resource	Credit Termination Date	Credit
Large Wind	January 1, 2013	30%
Closed-Loop Biomass Facility	January 1, 2014	30%
Open-Loop Biomass Facility	January 1, 2014	30%
Geothermal Energy under IRC sec. 45	January 1, 2014	30%
Landfill Gas Facility	January 1, 2014	30%
Trash Facility	January 1, 2014	30%
Qualified Hydroelectric	January 1, 2014	30%
Marine and Hydrokinetic	January 1, 2014	30%
Solar	January 1, 2017	30%
Geothermal under IRC sec. 48	January 1, 2017	10%
Fuel Cells	January 1, 2017	30%
Microturbines	January 1, 2017	10%
Combined Heat & Power (CHP)	January 1, 2017	10%
Small Wind	January 1, 2017	30%
Geothermal Heat Pumps	January 1, 2017	10%

Source: U.S. Department of the Treasury.

In addition to the PTC and ITC, the federal government's incentives through the ARRA and the Energy Bill Policy Act of 2005 include loan guarantee programs, research and development (R&D) grant matches, other R&D grants, loan guarantees, or direct loans for certain types of alternative energy projects including geothermal, fuel cell, and biomass, among others. For example, the ARRA includes $6 billion to support loan guarantees for electric transmission and renewable energy technologies, which allows the Western Area Power Administration to borrow up to $3.25 billion from the U.S. Treasury for transmission upgrades, provides $4.5 billion for the Department of Energy (DOE) to support the modernization of the nation's electrical grid system, and expands an existing clean energy bond mechanism – the ARRA allocates up to $1.6 billion for Clean Renewable Energy Bonds to be used for financing energy projects.

Several states have instituted renewable energy requirements as well as incentives to encourage and/or mandate the use of renewable energy. California, for example, offers feed-in tariffs and has a Renewable energy Portfolio Standard (RPS). California is one of 29 states plus the District of Columbia that have a RPS. Usually, a RPS requires a percentage of power to be provided by renewable energy. In most cases, not only does a company get credit for using a renewable energy, but it also can sell excess credits on the open market. States are currently taking the lead in instituting systematic changes to climate change policy as there is very little mandate at the Federal level, but this development can complicate the understanding of utilities as well as make financial projections more difficult – especially with utilities that have markets in more than one state, as no two states have the same policies.

Exhibit 40: Renewable Portfolio Standards by Jurisdiction

State	Deadline	Mandate	State	Deadline	Mandate
Arizona	2025	15%	Missouri	2021	15%
California	2020	33%	Montana	2015	15%
Colorado	2020	20%	North Carolina	2021	13%
Connecticut	2020	27%	New Hampshire	2025	24%
District of Columbia	2020	20%	New Jersey	2021	23%
Delaware	2019	20%	New Mexico	2020	20%
Hawaii	2020	20%	Nevada	2015	20%
Iowa	105 MW required		New York	2013	24%
Illinois	2025	25%	Ohio	2025	25%
Kansas	2020	20%	Oregon	2025	25%
Massachusetts	2020	15%	Pennsylvania	2020	18%
Maryland	2022	20%	Rhode Island	2020	16%
Maine	2017	10%	Texas	5,880 MW by 2015	
Michigan	2015	10%	Washington	2020	15%
Minnesota	2025	25%	Wisconsin	2015	10%

Source: Database of State Incentives for Renewables and Efficiency, as of 10/21/2009

Each state with a RPS generally has a deadline for getting to a specified percentage of power by a certain date. To understand this better, we look at Iowa and Arizona as examples.

Iowa requires that its two investor-owned utilities own or contract for a combined total of 105 MW of renewable energy, which they have already done. The breakdown by company is based on 1990 peak level demands and the percentage that each company contributed to this level. Currently, these two companies have met the obligation using a combination of wind and biogas.

Arizona law requires 15% of the retail load by 2025 to be from renewable energy. There are additional rules that include 30% of the 15% minimum needs to be from distributed renewable sources, credits can come from any year, and renewable energy systems must be deliverable to the state. This law applies to all investor-owned utilities serving retail customers in Arizona except those distribution companies with more than half of their costumer base located outside Arizona.

The very different laws by state only make a perceived complicated industry, well, more complicated.

Appendix

Bloomberg Command Table

Command	Description
COAL	Main menu for coal data
DIFF	Global energy differentials; Type “11” for regional gas differentials
EMIS	Main menu for carbon market and alternative energy
MFP	NYMEX energy futures prices
NATC	U.S. city gate gas/oil pricing
NATG	Main menu for natural gas data
NRG	Main menu for all energy data
NRGN	Main menu for all energy industry, statistical and macro news
NRGS	NYMEX gas strip calculator
OIL	Main menu for oil data
SPRK	Spark spread data by NERC region; Type “7” for regional gas costs by heat rate
VOLT	Main menu for electricity data

Source: Bloomberg.

Energy Conversion Table

	Gas (Mcf)	Coal (lbs)	Propane (gal)	Gasoline (gal)	Heat Oil (gal)	Residual Fuel (gal)	NGL Raw Mix (gal)	Electricity (kWh)	MMBtu
1 Mcf / Gas	1.000	83.300	10.916	8.000	7.194	6.666	11.05	293.083	1.000
1 ton Coal	24.000	2000.000	262.009	192.000	172.662	160.000	265.193	7033.998	24.000
1 gal Propane	0.092	7.633	1.000	0.733	0.659	0.611	1.012	26.846	0.092
1 gal Gasoline	0.125	10.417	1.365	1.000	0.899	0.833	1.381	36.635	0.125
1 gal Heat Oil	0.139	11.583	1.517	1.112	1.000	0.927	1.536	40.739	0.139
1 gal Residual Fuel	0.150	12.500	1.638	1.200	1.079	1.000	1.657	43.962	0.150
1 gal NGL Raw Mix	0.091	7.542	0.988	0.724	0.651	0.603	1.000	26.524	0.091
1 kWh Electricity	0.003	0.284	0.037	0.027	0.025	0.023	0.038	1.000	0.003

Source: Bloomberg.

State Utility Commissions

Name	Website	Investor Owned Regulated Electric Utilities	Number of Commissioners	Selection Method	Term (years)
Alabama Public Service Commission	www.psc.state.al.us	Alabama Power (SO)	3	Elected	4
Regulatory Commission of Alaska	rca.alaska.gov		5	Appointed	6
Arizona Corporation Commission	www.cc.state.az.us	Arizona Public Service (PNW); Tucson Electric Power (UNS)	5	Elected	4
Arkansas Public Service Commission	www.arkansas.gov/psc	Empire District Electric Co. (EDE); Entergy Arkansas (ETR); Oklahoma Gas and Electric Co. (OGE); Southwestern Electric Power Co (AEP);	3	Appointed	6
California Public Utilities Commission	www.cpuc.ca.gov	Pacific Gas and Electric Co. (PCG); San Diego Gas & Electric Co. (SRE); Sierra Pacific Power Co. (NVE); Southern California Edison Co. (EIX);	5	Appointed	6
Colorado Public Utilities Commission	www.dora.state.co.us/puc	Public Service Co. of CO (XEL)	3	Appointed	4
Connecticut Department of Public Control	www.state.ct.us/dpuc	Connecticut Light & Power (NU); United Illuminating (UIL);	5	Appointed	4
Delaware Public Service Commission	www.state.de.us/delpsc	Delmarva Power & Light (POM)	5	Appointed	5
District of Columbia Public Service Commission	www.dcpsc.org	Potomac Electric Power (POM)	3	Appointed	4
Florida Public Service Commission	www.psc.state.fl.us	Florida Power & Light (FPL); Gulf Power (SO); Progress Energy Florida (PGN); Tampa Electric (TE)	5	Appointed	4
Georgia Public Service Commission	www.psc.state.ga.us	Georgia Power (SO)	5	Elected	6
Hawaii Public Utilities Commission	www.hawaii.gov/budget/puc	Hawaiian Electric Company (HE); Hawaii Electric Light (HE); Maui Electric Company Ltd (HE)	3	Appointed	6
Idaho Public Utilities Commission	www.puc.state.id.us	Avista Corporation (AVA); Idaho Power (IDA)	3	Appointed	6
Illinois Commerce Commission	www.icc.illinois.gov	Central Illinois Light (AEE); Central Illinois Public Service (AEE); Commonwealth Edison (EXC); Illinois Power (AEE)	5	Appointed	5
Indiana Utility Regulatory Commission	www.in.gov/iurc	Duke Energy Indiana (DUK); Indiana Michigan Power (AEP); Indianapolis Power & Light (AEP); Northern Indiana Public Service (NI); Southern Indiana Gas & Electric (WC)	5	Appointed	4
Iowa Utilities Board	www.state.ia.us/government/com/util/index.html	Interstate Power & Light (LNT)	3	Appointed	6
Kansas Corporation Commission	www.kcc.state.ks.us	Empire District Electric Company (EDE); Kansas City Power & Light (GXP); Kansas Gas & Electric (WR); Westar Energy North (WR)	3	Appointed	4
Kentucky Public Service Commission	www.psc.state.ky.us	Duke Energy Kentucky (DUK); Louisville Gas & Electric (EONGY; Kentucky Power (AEP); Kentucky Utilities (EONGY)	3	Appointed	4
Louisiana Public Service Commission	www.lpc.org	Cleco Power (CNL); Entergy Louisiana (ETR); Entergy Gulf States (ETR); Entergy New Orleans (ETR); Southwestern Electric Power (AEP)	5	Elected	6
Maine Public Utilities Commission	www.state.me.us/mpuc	Bangor Hydro-Electric (EMA.TO); Central Maine Power (IBE); Maine Public Service (MAM);	3	Appointed	6
Maryland Public Service Commission	webapp.psc.state.md.us	Baltimore Gas & Electric (CEG); Delmarva Power & Light (POM); Potomac Edison (AYE); Potomac Electric Power (POM)	5	Appointed	5
Massachusetts Department of Public Utilities	www.state.ma.us/dpu	Fitchburg Gas & Electric Light (UTL); Massachusetts Electric (NGG); NSTAR Electric (NST); Western Massachusetts Electric Company (NU)	3	NA	4

Source: Oppenheimer & Co. Inc.

State Utility Commissions (cont.)

Name	Website	Investor Owned Regulated Electric Utilities	Number of Commissioners	Selection Method	Term (years)
Michigan Public Service Commission	www.michigan.gov/mpsc	Consumers Energy (CMS); Detroit Edison (DTE); Indiana Michigan Power (AEP); Upper Peninsula Power (TEG); Wisconsin Electric Power (WEC)	3	Appointed	6
Minnesota Public Utilities Commission	www.puc.state.mn.us	Interstate Power and Light (LNT); Minnesota Power (ALE); Northern States Power – Minnesota (XEL); Otter Tail Corporation (OTTR)	5	Appointed	6
Mississippi Public Service Commission	www.psc.state.ms.us	Entergy Mississippi (ETR); Mississippi Power (SO)	3	Elected	4
Missouri Public Service Commission	www.psc.mo.gov	Empire District Electric (EDE); Kansas City Power & Light (GXP); Union Electric (AEE);	5	Appointed	6
Montana Public Service Commission	www.psc.state.mt.us	Montana-Dakota Utilities (MDU); NorthWestern Energy (NWE)	5	Elected	4
Nebraska Public Service Commission	www.psc.state.ne.us	Black Hills Energy (BKH); NorthWestern Energy (NWE)	5	Elected	6
Public Utilities Commission of Nevada	pucweb1.state.nv.us/PUCN	Nevada Power Company (NVE); Sierra Pacific Power (NVE)	3	Appointed	4
New Hampshire Public Utilities Commission	www.puc.state.nh.us	Granite State Electric (NGG); Public Service Company of New Hampshire (NU); Unitil Energy Systems (UTL)	3	Appointed	6
New Jersey Board of Public Utilities	www.bpu.state.nj.us	Atlantic City Electric (POM); Jersey Central Power & Light (FE); Public Service Electric and Gas (PEG); Rockland Electric (ED)	5	Appointed	6
New Mexico Public Regulation Commission	www.nmprc.state.nm.us	El Paso Electric (EE); Public Service Company of New Mexico (PNM); Southwestern Public Service (XEL)	5	Elected	4
New York State Public Service Commission	www.dps.state.ny.us	Central Hudson Gas & Electric (CHG); Consolidated Edison of New York (ED); New York State Electric & Gas (IBE); Orange & Rockland Utilities (ED); Rochester Gas & Electric (IBE)	5	Appointed	6
North Carolina Utilities Commission	www.ncuc.commerce.state.nc.us	Carolina Power & Light (PGN); Dominion North Carolina Power (D); Duke Energy Carolinas (DUK)	7	Appointed	8
North Dakota Public Service Commission	pc6.psc.state.nd.us	MDU Resources (MDU); Northern States Power (XEL); Otter Tail Power (OTTR)	3	Elected	6
Public Utilities Commission of Ohio	www.puco.ohio.gov/puco.cfm	Cleveland Electric Illuminating (FE); Columbus Southern Power (AEP); Dayton Power & Light (DPL); Duke Energy Ohio (DUK); Ohio Edison (FE); Ohio Power (AEP); Toledo Edison (FE)	5	Appointed	5
Oklahoma Corporation Commission	www.occ.state.ok.us	Oklahoma Gas & Electric (OGE); Public Service Oklahoma (AEP)	3	Elected	6
Oregon Public Utility Commission	www.puc.state.or.us	Idaho Power (IDA); Portland General Electric (POR)	3	Appointed	4
Pennsylvania Public Utility Commission	www.puc.state.pa.us	Metropolitan Edison (FE); PECO Energy (EXC); Pennsylvania Electric (FE); Pennsylvania Power Company (FE); PPL Electric Utilities (PPL); UGI Utilities (UGI); West Penn Power (AYE)	5	Appointed	5
State of R.I. Public Utilities Commission	www.ripuc.state.ri.us	Narragansett Electric (NGG)	3	Appointed	6
Public Service Commission of South Carolina	www.psc.sc.gov	Carolina Power & Light (PGN); Duke Energy Carolinas (DUK); South Carolina Electric & Gas (SCG)	7	Elected	4
South Dakota Public Utilities Commission	puc.sd.gov	Black Hills Power (BKH); Montana-Dakota Utilities Co. (MDU); Northern States Power (XEL); NorthWestern Energy (NWE); Otter Tail Power Co. (OTTR)	3	Elected	6
Tennessee Regulatory Authority	www.state.tn.us/tra	Kingsport Power (AEP)	4	Appointed	6

Source: Oppenheimer & Co. Inc.

State Utility Commissions (cont.)

Name	Website	Investor Owned Regulated Electric Utilities	Number of Commissioners	Selection Method	Term (years)
Public Utility Commission of Texas	www.puc.state.tx.us	AEP Texas Central (AEP); AEP Texas North (AEP); CenterPoint Energy Houston Electric (CNP); El Paso Electric (EE); Entergy Texas (ETR); Southwestern Electric Power (AEP); Southwestern Public Service (XEL); Texas-New Mexico Power (PNM)	3	Appointed	6
Public Service Commission of Utah	www.psc.state.ut.us		3	Appointed	6
Vermont Public Service Board	www.state.vt.us/psb	Central Vermont Public Service (CV); Green Mountain Power (GZM-UN.TO)	3	Appointed	6
Virginia State Corporation Commission	www.scc.virginia.gov	Appalachian Power (AEP); Kentucky Utilities (EONGY); Potomac Edison (AYE): Virginia Electric Power (D)	3	Elected	6
Washington Utilities and Transportation Commission	www.wutc.wa.gov	Avista Utilities (AVA); Puget Sound Energy (PSD)	3	Appointed	6
Public Service Commission of West Virginia	www.psc.state.wv.us	Appalachian Power (AEP); Monongahela Power (AYE); Potomac Edison (AYE)	3	Appointed	6
Public Service Commission of Wisconsin	psc.wi.gov	Madison Gas and Electric (MGEE); Northern States Power Wisconsin (XEL); Wisconsin Electric Power (WEC); Wisconsin Power and Light (LNT); Wisconsin Public Service (TEG)	3	Appointed	6
Wyoming Public Service Commission	psc.state.wy.us	Cheyenne Light, Fuel & Power (BKH)	3	Appointed	6

Source: Oppenheimer & Co. Inc.

We identified 65 companies that own electric utilities or are independent power producers. Our list is by no means complete, but it represents nearly all of the investor-owned electric or natural gas utilities with electric plants. It also includes all the U.S. based IPPs.

Electric Utilities and Independent Power Producers

Company	Ticker	Company	Ticker
The AES Corporation	AES	Maine & Maritimes Corporation	MAM
Allegheny Energy Inc.	AYE	MDU Resources Group Inc.	MDU
ALLETE Inc.	ALE	MGE Energy Inc.	MGEE
Alliant Energy Corp.	LNT	Mirant Corp.	MIR
Ameren Corp.	AEE	Northeast Utilities	NU
American Electric Power Co.	AEP	Northwestern Corp.	NWE
Avista Corp.	AVA	NRG Energy, Inc.	NRG
Black Hills Corp.	BKH	NSTAR	NST
Calpine Corp.	CPN	NV Energy, Inc.	NVE
CenterPoint Energy Inc.	CNP	OGE Energy Corp.	OGE
Central Vermont Public Service Corp.	CV	Otter Tail Corp.	OTTR
CH Energy Group Inc.	CHG	Pepco Holdings Inc.	POM
Cleco Corp.	CNL	PG&E Corp.	PCG
CMS Energy Corp.	CMS	Pinnacle West Capital Corp.	PNW
Consolidated Edison Inc.	ED	PNM Resources Inc.	PNM
Constellation Energy Group, Inc.	CEG	Portland General Electric Co.	POR
Dominion Resources, Inc.	D	PPL Corporation	PPL
DPL Inc.	DPL	Progress Energy Inc.	PGN
DTE Energy Co.	DTE	Public Service Enterprise Group Inc.	PEG
Duke Energy Corp.	DUK	Puget Energy Holding	PSD
Dynegy Inc.	DYN	RRI Energy, Inc.	RRI
Edison International	EIX	SCANA Corp.	SCG
El Paso Electric Co.	EE	Sempra Energy	SRE
Empire District Electric Co.	EDE	Southern Company	SO
Entergy Corp.	ETR	TECO Energy Inc.	TE
Exelon Corp.	EXC	UIL Holdings Corp.	UIL
FirstEnergy Corp.	FE	UniSource Energy Corp.	UNS
FPL Group Inc.	FPL	Unitil Corp.	UTL
Great Plains Energy Inc.	GXP	Vectren Corp.	WC
Hawaiian Electric Industries Inc.	HE	Westar Energy Inc.	WR
IDACORP Inc.	IDA	Wisconsin Energy Corp.	WEC
Integrys Energy Group, Inc.	TEG	Xcel Energy Inc.	XEL
ITC Holdings Corp.	ITC		

Source: Oppenheimer & Co. Inc.

Glossary

Administrative Law Judge (ALJ)	An official in rate case proceedings who makes a recommendation to the Commission after viewing evidence and hearing testimony. ALJs were previously known as hearing officers.
Allowance for funds used during construction (AFUDC)	An amount recorded by the company to represent the cost of those funds used to finance CWIP. Amounts are credited on the income statement and capitalized during the construction period along with other construction costs.
Allowed return on equity	The return established by the state Commission that the company is allowed to earn on its equity investment.
Baseload generation	The amount of power needed to meet the minimum demands of customers. Usually the most efficient plants in the fleet.
Base rate	The portion of the total electric rate covering the general costs of doing business, except for fuel and/or purchased power expenses.
British Thermal Unit (BTU)	The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water by one degree.
Brownfield project	A project built on a site that already houses a plant – can be an addition or replacement.
Cap-and-Trade	Mechanism to control pollution by providing economic incentives to reduce CO_2 emissions. The controlling body will set a **cap** on the level of CO_2 emissions and issue “credits” to companies based on their specific level of emission. Cap-and-trade promotes efficient emissions reductions as “credits” can be **traded** in an open market. In cap-and-trade schemes, the cap is reduced over time to force a reduction in emissions.
Capacity factor	The ratio of the actual output of an electric power plant to the potential output.
Carbon dioxide (CO_2)	A colorless, odorless, non-poisonous gas that is a normal part of the ambient air. Carbon dioxide is a product of fossil fuel combustion. Although carbon dioxide does not directly impair human health, it is a greenhouse gas that traps terrestrial radiation and contributes to the potential for global warming.
Cogeneration	The simultaneous production of electric energy and useful thermal energy for industrial, commercial, heating or cooling purposes.
Combined cycle gas turbine	An electric generation technology that utilizes the heat waste from one or more gas (combustion) turbines to turn a steam turbine.
Construction work in progress (CWIP)	A balance sheet item representing accrued investment cost on facilities under construction.
Consumer Advocates Office	The intervener that represents consumers during regulatory hearings with the intention of keeping residential utility rates low. The office also provides information for consumers in deregulated markets interested in switching suppliers.
Cycling units	Units which operate with rapid load changes and frequent starts and stops, but generally at somewhat lower efficiencies and higher operating costs than base load plants. These units are generally either former base load units relegated to cycling units or newly built units for a lower megawatt rating which require less capital investment per unit of output than base load units.
Dark spread	The difference between the market price of electricity and the price of coal, adjusted for fuel efficiency.

Day-ahead market	The market for energy the following day conducted by the Independent System Operator (ISO), the power exchange and other scheduling coordinators. This market closes with the ISO's acceptance of the final day-ahead schedule.
Decoupling	Method of rate making which makes revenues independent of customer usage.
Degree day	A measure of heating or cooling where one degree day is counted for each degree of deficiency below (for heating) or excess over (for cooling) the assumed base on a given calendar day. The base temperature is often 65 F.
Distribution	The process of delivering electricity from convenient points on the transmission system to consumers.
Edison Electric Institute (EEI)	Formed in 1993, EEI is an association of U.S. shareholder-owned electric companies representing approximately 70% of the U.S. electric power industry. EEI provides a forum for the exchange of information between electric utilities and maintains a liaison between the electric industry and the federal government.
Embedded cost	Represents the total costs of all assets and ongoing charges "embedded" in the electric system which allows the utility to produce or deliver energy. In other words, the utility's historical average cost as opposed to its marginal cost. The embedded cost may be adjusted or normalized using current costs from the past test period.
Emission allowance	A permit to admit a certain amount of pollutants into the atmosphere.
Energy service provider (ESP)	In competitive markets and certain regulated states, an entity licensed to sell electricity to retail or end-use consumers using the transmission or distribution facilities of an electric distribution company. Services may also include metering, billing or power quality enhancement.
Environmental Protection Agency (EPA)	A federal agency established in 1970 to coordinate programs aimed at reducing pollution. The EPA is charged with safeguarding the environment by setting and enforcing environmental standards and developing and implementing environmental laws.
Federal Energy Regulatory Commission (FERC)	The federal agency with jurisdiction over the interstate transmission of electricity, natural gas, and oil and regulates wholesale sales.
Financial transmission rights (FTR)	A financial instrument allowing the holder to collect based on the congestion related price difference between two points on the transmission system. Also known as auction revenue rights or transmission congestion contracts.
Franchise service territory	A consent or permission, usually granted by governments or regulatory agencies, which in most cases allows exclusive rights to operate the equipment necessary to serve customers within the franchise area. Franchises are usually based on geographical boundaries.
Gasification	A chemical process using heat and pressure to convert carbon-containing material, such as coal, into a synthesis gas that can be used for low emission energy production.
Gigawatt	One gigawatt = one thousand megawatts = one million kilowatts = one billion watts.
Greenfield	A project site that has not been built on previously.
Heat rate	A measure of generating station thermal efficiency, computed by dividing the total Btu content of fuel burned by the resulting net kilowatt-hour generation.
Heat recovery steam generator	A heat exchanger which that recovers rejected heat from other processes such as gas turbines. It produces steam which can be used to power a steam turbine and more efficiently create electricity.

Hydroelectric generating station	An electric generating station that uses the gravitational force of water to produce electricity.
Independent power produces (IPP)	Power generators that are not affiliated with a vertically integrated utility.
Independent service Operator (ISO)	An independent control area operator formed at the direction or recommendation of the FERC with responsibility for ensuring the short-term reliability of the transmission grid. Similar to a RTO, but may not have the same requirements for regional configuration as an RTO.
Integrated gasification combined cycle (IGCC)	An electric generating technology where coal, water and oxygen are fed to a gasifier to produce syngas, which is then cleaned and powers a gas turbine. Additionally, the exhaust from the gas turbine and heat recovered from the gasification process are routed through a heat-recovery steam generator to produce steam to drive a steam turbine.
Interim rate increase	An increase in rates that is implemented by a utility during a rate case before the full case has been completed. The increase is often collected under bond or subject to refund. In some jurisdictions, rates may be implemented after a specified period of time, without specific commission authorization. In other jurisdictions, a commission order is required.
Intermediate load	The range of load between base load and peak load.
Interruptible power	Power delivery that is subject to interruption.
Interveners	Parties (including industrial customer groups, the Consumer Advocate, and competitors) that participate in rate cases.
Investor-owned utilities (IOU)	A privately-owned electric utility whose stock is publically traded.
Kilowatt	One kilowatt = 1,000 watts.
Kilowatt-hour (kWh)	A basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.
Load curve	A curve on the chart of power (kilowatts) supplied against time of occurrence. The load curve shows the magnitude of load as it changes over time.
Load duration curve	A graph of the amount of time during a period that electric power demand on a system is at a particular level. The capacity requirement in kilowatts is plotted on the vertical axis and the amount of time on the horizontal axis. The data is plotted in descending order of magnitude with the largest capacity requirement on the vertical axis.
Megawatt	One megawatt = one million watts.
Merchant plant	An electric generation plant that is not owned by a regulated electric utility. The output is sold to wholesale and / or retail customers.
Nameplant capacity	The full-load continuous rating of a generator as specified by the manufacturer.
Non-utility generation (NUG)	Generation that is not exclusively owned by a utility.
North American Electric Reliability Council (NERC)	Formed by the electric utility industry to promote the reliability of the generation and transmission systems.

Nuclear decommissioning	The process of removing a nuclear facility from service and cleaning all residual radioactivity to a level that permits release of the property and termination of the operating license by the NRC.
Nuclear Regulatory Commission (NRC)	The federal agency responsible for all aspects of nuclear power including regulation, inspection, safety, and design certification.
Off-system sales	Excess generation by a regulated utility that is sold on the spot-market. This is electricity that is not being utilized by the utility's customers and profits are usually shared with customers at a rate that is determined by the commission.
Peaking capacity	Capacity used to meet peak load needs when demand is highest.
Power grid	An interconnected network of electric transmission lines and related facilities.
Power pool	Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance program.
Public Utility Commission (PUC)	State regulatory agency that governs retail rates and practices. Also commonly referred to as Public Service Commission (PSC).
Public Utility Holding Company Act (PUHCA)	Enacted in 1935, the Public Utility Holding Company Act regulated the corporate structure and securities issuances of electric utilities and places limitations on utilities that are structured as holding companies. PUHCA was repealed as part of the 2005 Energy Act.
Public Utility Regulation Policies Act (PURPA)	One of five bills signed into law on November 8, 1978 as the National Energy Act. It set forth procedures and requirements applicable to state utility commissions, electric and natural gas utilities and certain federal regulatory agencies. A major aspect of this law was the mandatory purchase obligation from qualifying facilities. PURPA in its historical form was repealed as part of the 2005 Energy Act.
Purchased power adjustment	A charge to customers for electricity that was purchased from other sources
Purchased Power Agreement (PPA)	Long term contracts between parties for the purchase and sale of energy.
Rate base (Invested capital)	The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return.
Rate case	The process where a utility appears before its regulatory authority to determine the allowed rates.
Rate making formula	Revenue requirement = operating expenses + (rate base x rate of return).
Rate schedule	The rates, charges and provisions under which service is supplied to a designated class of customers. Also referred to as a service classification.
Real time pricing	A method of charging for energy based on the marginal cost of generation at the time of consumption. Smart meters inform customers of the current price so the end user can adjust consumption according to the price.
Regional Transmission Network (RTO)	A federally regulated entity independent of market participants with operational authority for all transmission facilities under its control.

Regulatory assets	An asset created when a regulated utility must capitalize all or part of an incurred cost that would otherwise be charged to expense. Over a period of many years, the asset will be reduced as the utility changes customers an extra fee to cover the cost.
Reliability must run units (RMR)	Generation units that are called on to operate out of merit order in order to resolve transmission constraints and to provide reliable operations for the system.
Reliability pricing model (RPM)	A capacity auction designed by PJM to establish forward capacity prices.
Renewable portfolio standard (RPS)	A regulation which requires the increased production of energy from renewable energy sources.
Revenue requirement	The amount of funds (revenue) a utility must take in to cover the sum of its estimated operation and maintenance expenses, debt service, taxes and allowed rate of return.
Reliability	The guarantee of system performance at all times and under all reasonable conditions to assure constancy, quality and adequacy of electricity. It is also the assurance of a continuous supply of electricity for customers at the proper voltage and frequency.
Securitization	A method of raising capital by issuing a security that conveys the rights to a particular revenue stream.
Spark spread	The difference between the market price of electricity and the price of natural gas. It can also represent potential gross margin for gas-fired power plants.
Stranded costs	Costs incurred by utilities to service their customers that may be unrecoverable in a newly-created competitive market as customers switch to cheaper competitors.
Stranded cost securitization	A process by which a utility borrows using a special charge to its customers as collateral. Stranded cost securitization can occur when a utility is given regulatory authority to recover stranded costs from its ratepayers, generally through a special charge.
Spent fuel	Nuclear reactor fuel that has been used to the extent that it can no longer effectively sustain a chain reaction.
Syngas (synthesis gas)	Name given to gases of varying composition that are generated in coal gasification and some types of waste-to-energy facilities. Syngas consists primarily of hydrogen, carbon monoxide, and often some carbon dioxide.
Test year	The 12-month period selected as a basis for a rate case.
Transmission	The act or process of transporting electric energy in bulk from the supply source to other principal parts of the system or to other utility systems.
Unbundling	Separating an integrated electricity chain into the components of generation, transmission, distribution, and retail in order to introduce competition.
Used and useful	The test used by regulators to determine whether an asset may be include in the utility's rate base.
Watt	The electric unit of real power or rate of doing work. One watt is equivalent to one joule per second.
Wheeling	The act of transporting electric power over transmission lines when the transporting entity does not own or directly use the electricity.

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